COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                 )
                                  )
Preparation of the 2007         )    Docket No.
Integrated Energy Policy        )    06-IEP-1K
Report (2007 IEPR)              )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 12, 2007

9:00 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

John Geesman, Associate Member

ADVISORS PRESENT

Suzanne Korosec

Gabriel Taylor

Tim Tutt

STAFF and CONTRACTORS PRESENT

Al Alvarado

Sean Biggs, Navigant Consulting, Inc.

Lisa Frantzis, Navigant Consulting, Inc. (via teleconference)

Ryan Katofsky, Navigant Consulting, Inc. (via teleconference)

Joel Klein

Richard McCann, M-Cubed

Jay Paidipati, Navigant Consulting, Inc. (via teleconference)

Anitha Rednam

Peter Spaulding

William Walters, Aspen Environmental Group

Lorraine White

ALSO PRESENT

Eric Wanless, National Resources Defense Council
and Union of Concerned Scientists

Mark Nelson, Southern California Edison

Tom Miller, Pacific Gas & Electric Company

Jane Turnbull, League of Women Voters

Gopal Shanker, R,colte Energy

I N D E X

P R O C E E D I N G S

9:12 a.m.

ASSOCIATE MEMBER GEESMAN: This is a workshop of the California Energy Commission's Integrated Energy Policy Committee. I am John Geesman the associate member of the Committee. To my right, Suzanne Korosec, my staff advisor. To my left, Gabe Taylor, Commissioner Byron's staff advisor. Lorraine.

MS. WHITE: Thank you, Commissioner. My name is Lorraine White. I am the program manager for the Integrated Energy Policy Report. I welcome you all to today's workshop at which we will be presenting information on the staff's developed cost of generation model and receiving your input in hopes of refining that model and making it available for public use.

Throughout the course of the day we will be providing as much information on the details of the model, its construction, its assumptions, what types of outputs we're getting, in hopes that we can engage your input on improving the tool itself.

In the morning part of the day we will be having presentations from staff, Joel Klein, Anitha Rednam and others on the model itself. We'll be providing a demonstration of that model, going through a summary of the results and assumptions, how we actually collected the data for those inputs and the analytic process that we went through to use that information within the model and receive the outputs.

We will also be discussing the limitations of the model that we have been able to identify to date and then soliciting your input.

In the afternoon we are going to go into a little bit more detail about some of the inputs, in particular about the alternative technologies and the assumptions that were developed for purposes of the model.

We are interested in getting input from parties, particularly on those alternative technologies of their interest. So if anyone has a particular alternative technology that they want explored in more detail please let Peter know.

As a part of the overall IEPR proceeding this is one of our efforts to ensure that the analytic tools that we're using are well-vetted, are addressed in terms of parties' concerns and questions. That we are able to develop and validate information that we use in other parts of our analysis. So it is very important that we receive input from various parties on the tools that we're using so we can refine them.

We are asking that in addition to the comments that we receive today we also have any written comments submitted by June 22. This will allow us to address those comments in a timely fashion and refine the model.

We want to consider all of the comments that we receive from the stakeholders in the model modifications and so timely responses are important.

Our goal is to publish the finalized staff report on the model, its assumptions and results by the end of July. And then post the model for people to use as well as a guide on using the tool with the staff report and make it available for public use.

If you have specific questions or seek information about either the IEPR proceeding or the cost of generation model itself this information is contained in the notice but I present it here as well just to make it easier to find. All of the IEPR-related information is on the Commission's website.

If you have general questions you can always contact me but then Anitha and Joel are available to answer questions specifically about the model being presented today.

With that, Commissioner, if you would like I will turn it over to Joel and we can begin the discussions.

ASSOCIATE MEMBER GEESMAN: Let's proceed.

MS. WHITE: All right, thank you.

MR. KLEIN: Before we go through our slides just a couple of more comments. I want to thank Lorraine, not only for that introduction but for the help that she has given us, particularly over the last couple of weeks. She has brought us back from the edge of despair several times. Thank you, Lorraine.

MS. WHITE: You're welcome.

MR. KLEIN: I would like to also tie this back to the previous IEPRs. The last time we did this was a 2003 IEPR. We didn't have one in 2005 because we were busy trying to get our next model and report together.

So those of you who have been following

this may have noticed that we missed one and we apologize for that. But I think when you see the model today you'll see that we put a lot of effort into it and maybe it's worth the waiting for.

We think we have probably the most user-friendly, transparent, flexible, well-documented model of its kind out there. So we're hoping with your help to make it the best it can be.

Now I myself always have trouble following speakers and who is up and what their name is so it might help you if you look to the end of the report. There is an Appendix A that has all the players, their names, telephone numbers and e-mail addresses, later if you want to contact any one of us.

Okay, with that we'll go into the slides and I'll turn it over to Anitha.

MS. REDNAM: Thanks, Joel. Okay, today we're going to cover the overview of the cost of generation model, the summary of the levelized costs, which is the output of the model. Then we'll review the assumptions, the input. Then our consultants will talk about the data collection along with Joel. How we process the data, the results. And finally the limitations of the model.

So the first is going to be the overview of the model. So basically what do the COG models do and who uses them and why are we doing this? Then I'll start with the model structure and I'll give a brief demonstration of the model.

So basically the models, they estimate the cost of technologies. You can compare one technology with another but it's misused commonly. And Joel will explain why they are misused and how we can rectify the problem.

Also we have modified our model to generate different curves like the annual cost curves, the screening curves and sensitivity curves. And another one is the wholesale electricity prices. I'll be explaining these steps in detail as we go along.

So the cost of generation model is a spreadsheet model. It basically calculates the levelized cost of various technologies. Normally a model does not generate screening and sensitivity curves. If you happen to look at the older version of the model, the 2003 IEPR one, we did not have any of this. We just had one value, the levelized cost. So this round it's different.

Who uses them? This is just a delineation of the number of requests we get regarding the model users and the users guide. So it is just for the information on how the model is used.

Slide seven. This talks about the inputs that are typically required for the model. Basically the plant characteristics are important. The general assumptions, that is the property taxes, insurance, the escalation rates, those are important.

Then the financial assumptions like the cost of debt, cost of equity, the life of the plant, book life, federal tax life so those are the inputs.

Then the outputs to its right you can see. I'm sorry this screen is not too good. We couldn't fit it into the page actually. So the output is the levelized fixed cost, then the levelized variable cost. So you get the total levelized cost along with the annual cost.

The screening curves which I've talked about, the sensitivity curves and the wholesale electricity prices.

I want to make this clear that the cost

of generation model gives the fixed component of the wholesale electricity prices.

The variable component we get from markets and another production cost model. From there you can get the total cost, the wholesale electricity price.

MR. KLEIN: Just a second. If you're having trouble reading this you might open the report itself. I think it's on page 45 or 46 there's a lot on this. It's not essential at this time that you follow this carefully.

MS. REDNAM: So this is the model structure. Basically the user selects the inputs, the one in the red. And then the macro collects the data from the plant type, financial and general assumption sheet.

And it's sent to the data one and data two where the initial calculations are done. And it's fed into the income statement.

From the income statement you get the results are sent to the output which are the annual values, the present values, levelized cost and we get the output on the output sheet.

This is a section of the input sheet. Like the plant type assumptions, all power plants specific data like the different technologies, everything related to the heat rates and fixed variable loan rates are stored in this sheet.

The financial assumptions, basically like the type of the ownership. Like whether it's a merchant-operated or a muni-owned or an IOU-owned. That's the financial assumption sheet.

Then the general assumptions. It's like specific for all the plants, common assumptions for all the plants. That's what the general assumption sheet does.

And the base year. The base year is the data for which, the plant data, available data. I want to make it clear here that for the CCs and CTs we got the cost for in 2005 dollars. All the alternative stuff we got the cost in 2006 dollars.

And the start here is where the plants starts, the first year. And the user can select the different kind of fuel prices which I'll talk about later and the area of the plant and the perspective.

We have two perspectives in the model. One that's the load center where you account for the transformer/transmission losses. The other one is at the bus bar right outside the plant so the losses should set to be zero there.

A more detail is the construction cost bases. We have two costs. One is the installed. And one is the instant.

So instant costs does not account for the financing and everything. It's just your overnight costs.

It should be noted that in the model for the combined-cycle and combustion turbine we got the costs at installed. That means we already accounted for the financing and everything.

Whereas for the afternoon section of the workshop we have costs and instant.

So this is the output, the total levelized cost and it delineates the fixed costs, the components of the fixed costs, the components of the variable costs.

As you can see for the fixed costs you have financing, construction, insurance, ad valorem, which is the property tax, the O&M taxes.

The fuel and the variable O&M is the variable cost section. So what is a levelized cost?

We talk about levelized costs all the time. What is it? This is a main objective of our model. It's a constant stream of payments for every year of the plant. So it's one payment.

You can see that the one in blue, it's an annual cost which varies ups and down. But it should be noted that the present value of both these payments are the same. So levelized costs is a better effort.

We use levelized costs because you have different book lifes for different plants. It can be easy to compare one technology against another. Annual costs, you can't do that.

Now is the interesting part, the model demonstration. Here the user can select the inputs which I talked about like the different inputs. We have total of 28 technologies.

So the user can select any technology they want. We have all the assumptions in the model right now.

And once you select the plant type assumptions then you can select the financial ownership, whether it's a merchant, or an IOU or a muni. So let me select an IOU for starters.

And the fuel price. Based on the technology the fuel. It should be noted that you can't select your annual for combined-cycle so you have to select something in the area, California area.

And then the starting perspective. We usually set it at the load center because we want to account for the losses.

This is the section with the levelized costs. The part I showed in the presentation and some key data values in the model.

If you scrolled what's right, these are the annual costs. The totals, the above one which includes both the fixed in the blue color and the variable.

As you can see the fixed costs tends to decrease after because we our loan is paid so your costs tend to go down.

And these are the components. The levelized costs as you can see the variable costs accounts for 73 percent for this technology. The fixed is 27 percent. We even have the cost components and percent.

The fuel makes up 67, tax credits four, fixed O&M two and property taxes one.

MR. KLEIN: Let me add something here if I could. When we first started with the model we were getting a ratio of 80 percent for the fuel costs. But one of the things we discovered is that some of these equipment costs were higher than we had thought.

And in the final analysis is the ratio depends on what fuel price forecast you have which we all know can be almost anything.

But generally speaking now we're finding that the ratio of the fuel price to the overall costs, as a percentage of overall costs is a little smaller than we've predicted in the past. Okay go ahead.

ASSOCIATE MEMBER GEESMAN: And what fuel price projections have you been using?

MR. KLEIN: Well the one we're using right now is a modified one from 2005 IEPR.

MS. REDNAM: I can show the fuel price.

MR. KLEIN: Just a second, Anitha is about to do something here. We're using this one. And actually what this is is we've taken the 2005 IEPR fuel price and modified the years 2006, 2007 and 2008 to be more consistent with more recent forecasts.

Now even this forecast now is a bit out of date because this work was done about a year ago by the fuels office. But what they did was they took the 2006 price, modified half the year on known data that they had actual data. The 2007 was --

MS. REDNAM: Forward prices.

MR. KLEIN: -- was scaled up to match the scale, actually scaled down to match the forward prices. And half of 2008 was scaled down to match it.

So we've tried to phase the early years in to match the more current gas prices. But again this is like a year old so.

ASSOCIATE MEMBER GEESMAN: And you take that out how far?

MS. REDNAM: To 2045.

ASSOCIATE MEMBER GEESMAN: So that's just a constant escalation rate or we don't do a forecast out that far do we?

MR. KLEIN: No, not at all. We've just escalated as best we can.

ASSOCIATE MEMBER GEESMAN: So when we actually or when the fuel office completes its work for this cycle is it your plan to then use that as your fuel price series?

MR. KLEIN: Yes we wait with great anticipation. And as you can see it's a simple matter to just drop those new set of numbers in to the model and it's done.

ASSOCIATE MEMBER GEESMAN: Thank you.

MS. REDNAM: Now I want to talk about the screening codes which we have adapted our model to do.

So screening codes are basically the compared to total levelized costs of one technology with another. Some are plotting the screening curves with the capacity factors on the abscissa and the dollars for megawatt hour. That is the levelized costs. And the ordinate we can compare different technologies.

For example I'll try to compare the advanced, combined-cycle with an advanced combustion turbine. And as you can see we can choose the levelized costs format in dollars per kilowatt year or dollars for megawatt hour.

Dollars per megawatt are as the most commonly used one. So I'll just say, okay. And here are the codes for this technology.

So we can notice from these curves where the combined-cycle crosses the combustion turbine. So it's an important comparison attribute the model.

But there is one disadvantage for the screening curves. It's just you're using one assumption just the capacity factor with respect to the costs.

The sensitivity curves. You can change different assumptions to see the effect of the assumptions on the levelized costs which we have captured too towards the right.

This gets the sensitivity curve and select the technology, for example, the H frame, combined-cycle. Choose the levelized cost units, dollars per megawatt hour.

We have the three ordinates here, levelized costs, change in the percentage or change in dollars per megawatt hour.

We can choose the variables, what we want to see like discount rates, the rated average cost of capital.

The cost of equity. You can select the fuel price and select the parameters, set the variable parameters and say, okay.

And you can see the different assumptions. The relative change in the levelized costs by changing the assumptions. Do you want to add something Joel?

MR. KLEIN: Yeah, I wanted to stop to explain why we have these curves. We're handing out data. You hand out one number and people use that number a bit too trustingly.

So we're trying to make this model into a form where it makes people more aware that these costs, these levelized costs we're giving them are susceptible to these other assumptions.

And we think these curves probably dramatize that as much as possible. I sort of interrupted Anitha I guess explaining this --

MS. REDNAM: Relative change.

MR. KLEIN: -- relative change. But down here if you go, here's your zero point and here's your value. Now if you increase any one of these values by let's say we take, what's our blue curve here? Yeah, fuel price.

MS. REDNAM: Yeah, fuel price.

MR. KLEIN: Okay, if you increase it by 20 percent you go up and then you come over this way and see how much it increases the levelized cost. We're at --

MS. REDNAM: Twenty percent.

MR. KLEIN: It goes from roughly 80 something to 120. So is that clear to everybody how this works or? Okay. Go ahead Anitha.

MS. REDNAM: Okay. So the other curves we did are the, Joel you have to talk about this. The WP forecast, this is Joel's, this is another part of a report which he delineated how we did the study for the wholesale electricity prices.

Like how we got the fixed components from the model. How we did the variable costs and got the total, wholesale, electricity price. So you just want to say a few things?

MR. KLEIN: Yeah, we're quite often asked to develop a wholesale, electricity price forecast, or example, for the retail, electricity prices.

And in the old days that was the market, clearing price. Because everybody was in the market. But now that everyone isn't in the market it's much more problematic as to how to do this.

I developed this technique here which is maybe a bit simplistic but it seems to be working quite well.

What I do is I assume the fixed costs are essentially equal to the fixed costs of a combined-cycle unit. And I get the variable costs out of the market sim model assuming that the average costs in any one year will be equal to that.

Now this is how I developed these numbers. And I don't want to belabor this too long because we don't have a lot of time today.

But for instance in 2001 I just run all the numbers from 2001 to 2005 for what the fixed costs are out of the model. Then I run it again starting at 2022 through 2025.

And I do that for each of the years. Now this just in each year is a single, combined-cycle unit. And this probably seems pretty simplistic. And I've done other perturbations but it does essentially work.

Now to really explain this to you it's an hour and a half. So I'm just going through it quickly. If someone is truly interested in learning more about this they need to contact me, Joel Kline. And I'll take them through it.

What we have over here is we get the total --

MS. REDNAM: Constant.

MR. KLEIN: -- yeah, we get the max, minimum --

MS. REDNAM: Average.

MR. KLEIN: -- and average. And the minimum is the cheapest plant that is on that year. The average is the average of what plants run on that year. And max is the most expensive unit on that year. And that's typically the first year of operation.

And what you get is a series of curves here so you can sort of pen it in. Now I haven't explained this very carefully because I don't have the time.

And it seems simplistic I know. But I've done a lot of perturbations like I've just said. And it seems to work pretty well. I've talked to other people who have spending a lot of time trying to get these prices. And it seems to work. That's what I can say.

ASSOCIATE MEMBER GEESMAN: What's the measure of it seeming to work?

MR. KLEIN: Well, one from talking to other people and seeing what their forecasts are. And from varying parameters like saying, I actually go back and I account for how many units were on in each year. And do more and more detail until it's energy-weighted. And it's still pretty close.

So as I vary parameters it still seems to be reasonably in there. There is no real perfect answer on this. If you look at the prices that are out there which of course I couldn't disclose because most of them are confidential. They're quite variable.

But mostly based on what I hear these prices are pretty much falling in this range. You can see prices out of this range because there are other factors driving contracts, other than the which simple, cost, average costs of the unit.

But it seems to work and it's fast. And it's not a gigantic part of most of these studies we do. So it doesn't have to be real precise. so being able to do something like this that I can do quickly.

And when you just do this one run you have when you click that thing once, that's all going to change because it set for an IOU now.

You've made some 20 odd runs and you're done. So we used to fuss around with this thing for weeks. Now I can pretty much turn one of these out, once I have a fairly good numbers out of the market sim model. I can use those for generally a reasonable period of time. And I can produce these estimates quickly.

ASSOCIATE MEMBER GEESMAN: But I don't, you're losing me on, you say it works well. You had to produce the numbers, I think you're suggesting that you think it works well because it converges with other forecasts from people that you've talked to. But that's all confidential information so if you told me you'd have to kill me (laughter).

MR. KLEIN: Well I hope it doesn't come to that but.

ASSOCIATE MEMBER GEESMAN: Are you suggesting that it provides an accurate forecast or are you suggesting that you can get the model to produce numbers?

MR. KLEIN: I think it produces reasonable nominal numbers. It's not precise. And I don't think there is a model that can do that.

ASSOCIATE MEMBER GEESMAN: What value would we attach to that as a policy makers since it doesn't appear to be any way for us to cross check it or validate it or even for that matter compare it with other forecasts.

MR. KLEIN: Well, I guess you start out

by saying all models are wrong but you hope that they're helpful.

ASSOCIATE MEMBER GEESMAN: Well that's what we say about Commissioners (laughter).

MR. KLEIN: Well I hope you're doing better than our models but --

ASSOCIATE MEMBER GEESMAN: Nobody tests us.

MR. KLEIN: But we do think that these, you know, it's my feeling and I don't, I guess I'm at a loss for words to convince you to what degree you can at this exact moment that you could rely on this as a policy maker. But maybe I need a little bit more time to ponder that to give you a real good answer but.

ASSOCIATE MEMBER GEESMAN: Yeah, where I'm worried Joel is Senator X says, well tell me what the price is going to be in 2020. And I come back with, well Joel says that this was quick and it works and it corresponds to what he thinks other people are talking about on the basic, confidential forecast and the price is 20 cents. Do I want to encourage Senator X to rely on that type of projection?

MR. KLEIN: Well, Richard was just

saying something to me which maybe helps or not but. And maybe I didn't make this clear but we have actually had privilege to some contract prices and it seems to correlate with those contract prices. I don't know if that's Richard's impression that it would help you or if that actually helps you but -- We can't necessarily disclose those prices. But we --

ASSOCIATE MEMBER GEESMAN: And it corresponds based on those contracts using the same fuel price forecast? I'm sorry, I'm searching here for what the significance is.

MS. REDNAM: Get Richard.

MR. KLEIN: Okay, let Richard try this one.

MR. McCANN: Yes. Commissioner, I understand, actually I agree with your frustration of not being able to see contract prices and how they're derived. But what Joel has done is he's reviewed some of the contracts.

Now the thing about a contract that is developed is the fuel price forecasts and all of the underlying assumptions that go into those price forecasts often are not revealed. All you have is the prices.

And that's actually -- the way that a market works is that often what happens is the price that you see is actually a summation of all of this other information that the parties have about the various markets. And it is not explicit about how they end up arriving at that contract price. They just happen to arrive at a price.

So what this model does is it actually ends up arriving at something that looks like the contract price and in some ways we're backwards engineering that contract price. We don't have the contract prices. We don't have what goes into the contract prices. But we say, this comes out pretty close.

Now our assumptions that go into this model, which are really pretty well vetted in terms of the fuel price forecasts and the component, the cost of the components, we can say, well those contract prices must use assumptions that look something like what we've got in our model. So in some ways we make the contract prices transparent by backwards engineering them.

But we don't, the contracts themselves we don't have the underlying assumptions and we'll never get the underlying assumptions.

ASSOCIATE MEMBER GEESMAN: Right, right, thank you.

MS. REDNAM: Do you want to add anything on the sensitivity, Joel?

MR. KLEIN: I'll add one thing. I think ultimately any analysis until it's subjected to scenarios or risk analysis is always questionable. The singular number that you get or stream of numbers that you get are a stream of numbers. And I don't have to tell you that, you know that.

The real value in these studies, I think, is if you can develop scenarios or some form of risk assessment that leads you to believe that you have some degree of confidence in this. Okay, I think that's about all I can add.

MS. REDNAM: Okay. Now Richard will continue with slide 13.

MR. McCANN: I'm Richard McCann with M-Cubed. I want to start by thanking Eric Cutter who is in the audience who was instrumental in developing the model in its early stage and did a lot of this as a subcontractor to M-Cubed and moved on to E-3 later on.

I'm going to explain a little bit about the income statement. The income statement is basically where all of the calculations are done for the various cost components. And you've got this chart that's got print that is too small for you to see of how various things work. But I'm going to go through and try to summarize a little bit in terms of the things, the components and how they work.

The income statement just to begin. This particular model is set up so that the solution target is arriving at a levelized return on capital and financing costs. And I mentioned this is a technical question. It's a little bit different than the PUC's MPR model which actually uses a levelized total cost component.

The way it's done -- We did it two different ways because of the way that the model has to solve and kind of the algorithm, the computer algorithms. The way that we did it here is one that allows for a little bit more flexibility. One of the things that we're considering is whether in the next iteration to have an alternative solution methodology that we can use for this particular model. But we end up with an answer.

Joel has checked the answers against the

MPR model and the results come out quite similar for a combined cycle power plant using the two different methods.

So what we have is there's the various components of the model that are in the income statement. We have the capital and financing costs, which are the return on equity. We have the capital and financing costs, which are the debt and financing costs, return on equity.

Then we have the insurance costs, which are fairly obvious. We have ad valorem costs, which I'll talk a little bit about, but that has to do with the property taxes that are paid on the installed investment that's there. And we have fixed O&M costs, which are costs that are invariant with the usage of the plant. They just basically are the same year to year.

We have various state taxes and incentives and federal taxes and incentives, which gives us a total corporate tax on the particular project. And we have total fixed costs. Basically that's a summation of these lines one through five.

Then we have some of the variable cost components. We have the fuel cost, the variable

O&M costs and then the total variable costs, which is the sum of the fuel costs and the variable O&M. And then we have a total generation costs, which is a summation of lines six and nine, which are the total fixed costs and the total variable costs.

And what we do is we also have in this model the ability to look at three different ownership modes. We have the merchant power plants, investor owned ownership configuration and then the publicly owned utilities or municipal utilities.

So within each one of these we actually have -- in some cases the costs are calculated the same way and in other ways they vary by ownership structure.

So for example on the merchant costs we have the debt payment x the percent of debt + the levelized total equity return x the percentage of equity. So that a power plant might be financed 40 percent debt and 60 percent by equity, which is a typical merchant plant financing structure from what we've seen from the Board of Equalization.

So we multiply those together and end up with a total return on the project, which might be ten, ten and a half percent, for example, for a merchant power plant.

The IOUs use a similar structure. What we have to do there is make an adjustment because they get return on book value as prescribed by the Public Utilities Commission. The merchants financing is more flexible, it's much more prescribed for the IOUs.

And then we also have the municipal financing structure, which we assume is 100 percent debt payment, debt financed.

ASSOCIATE MEMBER GEESMAN: And is there an effort on those financing costs to customize your assumptions to California entities?

MR. McCANN: Yes, because for example, on the merchant power plants we used the Board of Equalization's assumptions when they do property valuation. So they have done a capitalization study and we use the inputs from the capitalization study from the Board of Equalization. So --

ASSOCIATE MEMBER GEESMAN: And for the IOUs you attempt to simulate the three California IOUs?

MR. McCANN: We used an average. Again

I think we drew from the Board of Equalization study, is that right?

MS. REDNAM: Yes, we did.

MR. McCANN: So the Board of Equalization had done this also because they assess the property value for investor owned utilities. So we went to the BOE to use a common set of assumptions.

ASSOCIATE MEMBER GEESMAN: And the munis, a California cost of debt?

MS. REDNAM: One hundred percent financed.

MR. McCANN: Right. What we did there is we chose from a selection of bond issues from munis for different lives and put that in. And all of this information can be easily updated, particularly for the merchant and the IOUs.

There's actually, the BOE wrote a formula that we can tie to the US Treasury rate. So we can pick, there's a website we can pick the US Treasury rate off of, plug it into the formula and update the return information actually quite easily.

ASSOCIATE MEMBER GEESMAN: But if I were in Texas, before I just blindly used your assumptions I'd want to make certain that they were appropriate for the types of companies in Texas.

MR. McCANN: Exactly.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. McCANN: Yes. The insurance rates we have calculated somewhat differently between each one of these but it's pretty straightforward in terms of the calculation.

The ad valorem rate, which is a property tax rate, it varies by ownership quite a bit. Again we went to the BOE and used the BOE's adjustment factors for the merchant and the IOUs.

The publicly owned utilities was a bit of an issue because they actually don't have to pay taxes but very often they pay in lieu taxes. The problem is that whether they pay in lieu taxes or not depends in the type of muni they are.

For example, if they build a power plant inside Los Angeles -- If they built a power plant inside Los Angeles they would not make an in lieu payment. They would just take the extra return and put it into their city fund. Versus if SMUD built a power plant in Yolo County they would pay Yolo County an in lieu property tax amount. So we have an assumption in there about in lieu payments which is roughly equal, right at the moment equal to a merchant power plant but you can set that to zero in the model as well.

We have fixed O&M, which has a labor cost plus maintenance costs. The labor costs were actually derived from Bureau of Labor statistics and a very detailed model. Actually Will Walters is going to talk about how we developed estimates for some of these components in fixed O&M.

The state tax incentives. that was actually one thing that we went through and it turns out to be a very complex equation that we were actually working on up until the end of the presentation of this model. There are --

Particularly for alternative technologies, if this calculation is not done in a correct, detailed way you will not get a correct answer. We found that it really makes a significant difference in the results and it is not clear that it is always carefully done by other people doing this kind of analysis. And the same thing for the federal tax impacts.

And then for the variable costs we basically used the same equations for each one of the variable components for the various power plants. Some of the data varied a little bit by power plant type. Are you going to talk about the QFER data later? I can't remember.

MS. REDNAM: Yes, yes.

MR. McCANN: In the fuel cost data we actually did something pretty innovative in terms of trying to calculate how the fuel costs and the heat rate varies by capacity factor and Anitha is going to talk a little bit more about that.

That's basically the core of the model is this income statement, which has given us some flexibility in terms of being able to look at different ownership structures for these, for these different power plants.

MS. REDNAM: Also we used different escalation rates.

MR. McCANN: Right. The escalation, we have different, real escalation rates beyond just general inflation --

MS. REDNAM: Inflation.

MR. McCANN: -- within the model for some of these components as well. The capital and financing versus the fixed O&M versus the variable O&M. Each one of those things is separately calculated in the model as well.

MS. REDNAM: Thanks, Richard.

MR. KLEIN: Can I?

MS. REDNAM: Yes, please.

MR. KLEIN: I'd like to just add one thing. Richard was talking about how you get quite a different answer if you do this correctly. And I wanted to give you a numerical example. We took one of the alternative technologies and ran it both the old way and the new way and it reduced the cost -- Let me back up. Without making any particular change at all in a traditional technology like a CC or CT it made as much as a 20 to 25 percent reduction in apparent installed costs. So it's quite a, in some cases it's a dramatic change.

MS. REDNAM: Okay, thank you. Since we covered the overview next is the summary of the levelized costs. How we got the output. So we listed them in kind of a table and graphical format. If this is hard for you guys to see you can turn to page seven on the report.

These are the costs based on the ownership, one for merchant or an IOU or a muni. And they're listed according to megawatts and in both units, dollars per kilowatt year and dollars per megawatt hour.

The same table is provided graphically. So as you can see the costs are all the way over.

This is the subset of the previous table. Delineation of the merchant by component, the different components like capital & financing, insurance, all to get the total fixed cost and the fuel prices to get the total variable cost.

And again this is presented graphically for better understanding.

Then the review of the assumptions. I barely covered the assumptions on the previous slides. These are the minimum assumptions we need to get the outputs for the model like the plant characteristics, the general assumptions, the financial and instant and installed costs. The O&M, fixed O&M and variable O&M. And the fuel prices. They're a big contributor to the cost.

This is again presented in a table format. So the combined cycles and simple cycles, we did a data survey of 34 plants and we got actual operating -- actual as-built and as-operating costs, which Will Walters will discuss in detail. So they're on different capacity factors. Again, we got that information from actual data. It's fixed O&M, variable O&M.

For the alternative stuff we got it from Navigant, who did a study and got this information by talking to people. So they will be covering that in the afternoon section.

Slide 22 is important because of the emission factors in pounds per megawatt hour. And based on the technology, again, the emission factors are factors. And for the combined cycle and the combustion turbine we got it from our office, the environmental office in the Energy Commission. For the others we got from Navigant.

Slide 23 shows the difference in the instant cost calculated by Navigant versus the CEC. Just due to the fact of the emission factors Navigant people gave us the input, which we entered into the model to generate the total instant cost. Here you can see like for technologies where there are no emission factors like wind, solar, PVs, solar parabolic troughs, Sterling dish, the values are the same. But for technologies where there are emissions, like biomass, the costs are different.

Now Joel will continue with the data

collection.

MR. KLEIN: Okay, this is restating probably the tenth time. This morning we're just covering the top bullet, combined cycle and simple cycle units. This work was largely done by Will Walters but we all pitched in on this. In the afternoon you'll get the data on the second bullet. So I thin I'll just have Will come up now and tell you how it's done.

MR. WALTERS: Well what we did is we provided a survey to get cost information from the post-deregulation power plants that fit essentially what we were looking for, which is the combined cycle and simple cycle plants.

So there were a few plants that have been built post-deregulation or updated since post-deregulation that we did not include in the survey because they didn't really fit the parameters and wouldn't be good cost comparisons. Those would be -- There were a couple of cogens, or at least one cogen, and the Huntington Beach remodernization for the boilers. So those were not included in the survey.

Otherwise essentially everything that has been licensed and operating since 2001 postregulation, was part of this survey. As long as it started operation essentially before we sent out the survey mid-last year.

As you can see there are 19 combined cycle plants. One thing I would like to note is that some of the notes or subscripts on the 2006 plants, actually in both columns are missing some things. Palomar in fact needs a 3 since it is an IOU, Consumnes and Walnut of course are munis so they should have 1 subscripts. And Ripon and Riverside are both munis and were both SPPEs so they should both have 1 and 2.

ASSOCIATE MEMBER GEESMAN: Palomar is in San Diego County rather than Kern.

MR. WALTERS: Excuse me?

ASSOCIATE MEMBER GEESMAN: Palomar is in San Diego County rather than Kern. Paloma I think may be in Kern. But I think you're probably focused on Palomar, which is a combined cycle.

MR. WALTERS: You're right. Okay, a couple more things to fix in the table.

So in terms of the survey the things that we asked included a number of capital cost parameters and operating and maintenance cost parameters. You can see it went from larger scale items such as gas turbine cost, make and model information. A lot of this information we actually knew or thought we knew so in the survey we put what we thought was correct and then asked them to, to revise it.

For example in the water treatment facilities we either would indicate they didn't or didn't have ZLD. And basically if we were wrong then we would get corrected and be able to update what the plant design was for each of the plants.

And as you can see we went after most of the major cost factors including the cost of the different linears that connect to the facilities, as well as the major and large differentiators really between the different type of projects.

And what I mean by differentiators, they're specific design items that a project may or may not have. Whether that, whether that is a specific type of turbine or a specific type of configuration, whether it's a two-on-one or a three-on-one or a two-on-one plus a one-on-one in terms of the gas turbine and steam turbines.

Whether or not, you know, it has a cooling tower or is air cooled, of course. Those of us who know, there's only the one air-cooled right now which is Sutter. At least in terms of the big plants and combined cycles. And the other differentiators included air treatment without chillers or evaporative cooling or nothing in a couple of cases.

And then for the operating costs we asked for again, a number of factors. We asked for operating hours in order to coincide that with the QFER data to kind of figure out how they were operating, to get more information on that. The QFER data, for those who don't know, is essentially quarterly data that CEC gets in in terms of the total amount of megawatts and fuel usage for each of the plants. Which is essentially as-operating data for each of the quarters as reported by each of the jurisdictional plants.

We asked the natural gas sources. In some cases there's more than one source. Having that information as background is useful for us in determining cost factors.

We asked for duct burner natural gas use so we could evaluate those facilities that had duct burners versus those few that don't.

We asked for water supply source and

cost and consumption so we could relate to the different types of water supplies, reclaimed, potable water, well water or other non-potable sources and relate those costs to those different types of facility setups.

We asked for the amount of labor. Essentially the number of man equivalent, person equivalent if you want, for each of the plants and the different types of staffing, different levels, as well as the, as well as the annual cost for that.

We asked for other items, some of which after getting the numbers didn't turn out to be major items, such as the annual regulatory costs. We also asked for the maintenance costs, including major overhaul costs, to get a better idea of how to integrate that or not integrate that into the cost of gen model.

PRESIDING MEMBER PFANNENSTIEL: You asked for all that information for these 34 plants. Did you get complete information? Do you feel that the set of numbers that you have to work with represents a full set of information on the 34 plants?

MR. WALTERS: Is all the data complete?

No. Is all the data good? No. A lot of the work in terms of getting the survey back was going back through the data, calling the facilities where the information either was missing or was not lining up with the rest of the data from other facilities where you would expect it to be similar and finding out what's going on.

In many cases what we had to do -- in terms also, in terms of what we asked for. The 2006 plants we only asked for the capital costs. They were not operating long enough to get any sort of reasonable operating costs.

But in going back through in many cases I was able to get updated, refined information for the various items. Or I was able to determine that they were not able to give me a good enough answer to actually include in our later data processing.

And one of the most time consuming parts of this whole thing was going back and calling and making sure that the information was in good shape, or at least identify those that were in good shape so that I can discard data that we determined were complete outliers for the specific items.

In some cases when we were looking at the data it became less important when the item was such a small cost factor it wasn't something that was going to get integrated into the model. But for some of the bigger cost items it was important to try to make sure that everything we were using was reasonably precise.

With any survey like this you're going to get different levels of information, whether it's completeness. In one case all we got was a total, a total cost. That was all we were able to get. And they told us why they were doing that and we accepted it based on their reasoning.

PRESIDING MEMBER PFANNENSTIEL: But I take it you're pretty comfortable that nothing is really skewed in the inputs to the model using this data.

MR. WALTERS: Nothing in terms of how each of the facilities were designed and built. There are other factors that you have to realize that go into each of these facilities that are all their own, their own design. A lot have their own problems that came up. One of the reasons that Joel had me do this work is I had been working on siting cases since 2001 and know most of if not all of these projects to some degree, either working on other projects through them or directly working through the siting case for them.

Now once we got the data back we had to start setting up what we wanted to put in the model. What we were going to consider a base case. And I'll go through the different parameters on what we consider base case and why we made those selections.

First we're using 500 megawatt and that's fairly standard for what we're doing, which is a non-duct fired, two 7F frame power plant configuration. Which as you can see is the two turbine/one steam generator configuration, which is fairly standard for this size. And this is the basic size range that we're using. Partially due to that's how it's been done, partially due that other models use that same type of size configuration. So we're being consistent with like the MPR, for example, that uses the two-on-one at 500.

In terms of the turbines we selected the GE 7F. And we did that because that's the typical. It's the one that, at least in terms of our survey, was the dominant turbine used for this configuration and all of the larger combined cycles.

We selected wet cooling, again because it's the dominant. In the future that may not be the case. You know, I've seen some of the later siting cases, the ones that are coming in now and one revision that I'm not sure if it's in yet, there are at least three or four more dry cooling proposals that are coming in and that may be built. Of course now we only have the one so we retained wet cooling s being the typical configuration for the typical design.

And again for a greenfield site. It was the predominant for these large plants rather than being a brownfield site. And again non-urban was typical so we selected that for the land cost.

We used reclaimed water source. That one, really the types of water sources, there were three or four that we had to deal with. And we went more with the future-casting on that one because reclaimed is becoming the dominant and we're seeing it more and more so we selected that for costing purposes as the type of water that these plants would be using.

ASSOCIATE MEMBER GEESMAN: Does that,

does that particular assumption carry with it an implied urban siting, or at least proximity to a reclaimed water source?

MR. WALTERS: Yes, there would have to be proximity to a reclaimed water source. But that doesn't necessarily have to be what we would consider an urban, an urban site.

ASSOCIATE MEMBER GEESMAN: And you feel that it potentially remains consistent with your non-urban land cost?

MR. WALTERS: Based on the projects that we reviewed we see reclaimed on both.

ASSOCIATE MEMBER GEESMAN: Yes. I guess my apprehension is that that may be a rear view mirror perspective in terms of what's come in over the last seven or eight years and not necessarily predictive of what would be likely to come in over the next seven or eight.

And I don't have a better way to do it than the way you've done it. But it occurs to me that if your sites ultimately are more remote you may have a problem getting access to reclaimed water. Which would call into question your ability to use the wet cooling assumption as well.

MR. WALTERS: Right. And there are a

couple of factors we'll get into after this slide that can allow the user of the model to make corrections if they want to go away from the base case configuration.

In terms of the water costs. I don't believe the difference between reclaimed and other sources is as big a factor as say --

ASSOCIATE MEMBER GEESMAN: No, it's very small.

MR. WALTERS: -- as say wet to dry cooling would be.

ASSOCIATE MEMBER GEESMAN: Yeah. Do you think we're going to site another freshwater cooled project?

MR. McCANN: I guess our point is it actually won't make a difference in the cost.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. McCANN: That's the way it ends up in the model.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. WALTERS: Next, the typical configuration has evaporative coolers or foggers. Very few chillers are used for the large combined cycle plants. There are a few. A couple in Blythe, for example. But typically they have the evaporative coolers or foggers for the --

ASSOCIATE MEMBER GEESMAN: And you don't see the use of chillers as a trend going forward?

MR. WALTERS: Not for combined cycle. Really the only time you typically see it for combined cycle would be in the desert-type situations. At least that's what the data has shown. If you're coastal you really don't need it that much anyway.

ASSOCIATE MEMBER GEESMAN: And do you see us getting more coastal applications coming in?

MR. WALTERS: We're getting a lot of applications that are on the fringe of the coast. Or at least we're working on quite a few right now.

ASSOCIATE MEMBER GEESMAN: That would not, not entail chillers?

MR. WALTERS: That I wouldn't expect would want to use chillers.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. WALTERS: And the typical plant, in fact almost all the plants have both selective catalytic reduction and oxidation catalyst. There are a couple of the older ones that don't, don't have oxidation catalysts depending on the siting. If they're in an area that has better air quality they've been able to get away with it. And there may be, that may happen again in the future. But it's not a huge cost factor and it's frankly not all that likely anyway.

The next one, again we're looking more towards the future for the zero liquid discharge and we're just seeing that happening more and more as a prevalent technology rather than, particularly if we stay with the wet cooling. They would, they would combine. Actually with the dry cooling they would be more likely because there is so much less water for them to have to treat.

The others. Not co-located with other power facilities. Which can dramatically reduce certain costs like linears, which have close availability and tie-ins. And that's typically the case. There are some cases where we see either expansions of facilities or facilities built essentially right next to existing facilities. But we see that more with municipal than we do with merchants. Although obviously Los Medanos and Delta would be an exception on the merchant side.

And last, we're assuming everything is in the 12 month licensing process. Number one, for this size they can't be SPPE and all the other processes are off the books right now unless there's more legislation to add a four- or six-month back into the system. Again, we don't expect anything beyond the 12 month.

And in terms of the total cost we came up with for these, for this base configuration assumption for the 500 megawatt plants. You can see we came up with different costs for merchant, IOU and muni. There are essentially the two IOU plants and there are three or four munis, I believe, in the CCs but it's back in that previous chart.

As you can see they are all fairly close to one another. The munis came in a little bit cheaper and the other two, the IOUs and the merchants came in very similar for the combined cycles. A lot of that I think had to do with the similarity in the designs.

The linears, as you can see, the munis tend to be setting up close to where they have existing facilities so their linear costs tend to be lower. And the permitting costs and the ERC are a California average to determine this base California number, which then can be modified for specifics.

We also did work for a combined cycle case with that firing, which is the 500 megwatt unit. It advanced 800 megawatt, which would be two H-frame type facilities like the Inland power plant that is being constructed right now. And you can see the cost comparisons again between those that were determined.

And the advanced, essentially what we did is we took data that was available, federal data from EIA if I remember right, remember the acronym right, and used their information. Essentially ratio and costs based on the conventional, with what they had since their costs and our costs really aren't in the same range due to probably many factors such as not including linears in their total costs.

ADVISOR TAYLOR: Will, did you do any sensitivity analysis in the input assumptions for the base case, the 12 input assumptions? Any formal sensitivity analysis.

MR. WALTERS: Well we, in doing the

analysis we did look at -- going to the next chart I guess to answer your question. We did look at what happened if you do or don't have some of these various factors in the design.

And in fact we determined if somebody asks for a particular configuration what do we do to the costs in order to change that configuration if we can't otherwise implement it in the model itself. What happens if you add a chiller, what happens if you're going to do dry cooling, you know, for the base case costs here.

And as you can see we had several factors. Plume abated cooling tower is one option. There are several of those out there and maybe some more in the future. If you don't have an oxidation catalyst, you can see it's a very small factor it's only $4 per kilowatt in terms of the total capital cost. Urban site, which is a little bit of a hit, for land costs. And also if you have a co-located muni you can see what happens. The various factors drop the cost fairly significantly.

ASSOCIATE MEMBER GEESMAN: How did you come up with your dry cooling cost?

MR. WALTERS: Pretty much based on

Sutter and also looking at other data from other plants. You communicated or used the word back-casting. Well, the survey is back-casting. We used the data as we got it, looking at what was good and bad data and using it that way. So we are sort of forecasting with this data. But it's certainly better than the old AFC data that we had in the past, which in many cases was wildly off from what the total were once they actually got the facilities built.

As you can also see we have some changes that are available for different turbine types. You can even make some assumptions on multiple, much smaller turbines, 7Es. Also some GGX100s, the LM6000. And these are related to basically differentials in just the turbine costs themselves in terms of integrating that amount of megawatt into a 500 megawatt plant.

Now for the simple cycle, which are a little simpler facilities, obviously. What we assumed was a 100 megawatt plant, which is essentially a typical design. Two LM6000 turbines. Or essentially 100 megawatt, just a little bit less. The wet cooling or dry cooling isn't a huge factor for these facilities because they don't have a lot of heat load so it wasn't important to really designate which one it was.

Here we assume a brownfield site. Again, because that was typical. That's what we were seeing. A lot of more were on previously used pieces of land. They weren't either on an ag land or on a true greenfield, you know, pristine piece of land.

Again we assumed non-urban land cost. It just turns out that most of the power plants are being built further away from urban centers. Probably because it's just easier to do, easier to site.

And for these because of the low water use we're assuming a potable water source. Again it's not a huge factor one way or the other but that's the typical situation for these plants because they don't use very much water. They just hook up to whatever is available nearby for potable.

We are again assuming evaporative coolers and foggers rather than chillers. This one was kind of a 50/50 in terms of making the call. We probably could have addressed that with an adder for adding chillers if we needed to.

For the air quality, again SCR and oxidation catalyst. I believe all of the facilities had that configuration for the simple cycle.

We are assuming ZLD for these facilities. Again that's somewhat future-casting based on the fact that we expect more facilities to do that. And again, a lot of them because they don't use a lot of water it does not cost them that much to actually have a ZLD system in.

And again we're assuming not co-located as part of the base configuration.

And again, here are the costs that we've determined. One of the issues that we do have to work at is where we're going to put the IOUs. Right now we're essentially making them equal to a merchant. We're going to have to take a look at some more information.

We've just recently been getting information from SCE on some plants that they're building in Ventura and South Coast Air Basin area. I've tried to get some updated information, they're only partially built so I've only got partial numbers right now.

It looks like the IOUs are tracking

somewhere between these two numbers. A little bit higher than these, maybe about right in the middle based on trying to figure out where the completion was and what has and hasn't been put into the total cost estimate yet. Their as-built right now I think was like at 600.

I believe we got this information through Commissioner Geesman as a matter of fact. It ended up to me. And unfortunately I wasn't able to reach anybody at SCE to try to get some updated numbers or some forecasts for finals on all of those. But like I said, the partial right now is at 600 and they are only at 36 percent complete on the construction.

I think most of the equipment costs have been dealt with. There's still a lot of construction costs that will come in and bump that number up, I think at least over the base installed cost numbers that we have.

And here are the linears. They all seem to track about the same between merchant and muni since we only had merchant and munis to compare at this point. And in these the permitting and ERC costs are considerably less, as you might expect, for these much smaller facilities that oftentimes have reduced hour numbers so they don't have to get as many offsets.

And again here's a comparison. Below is a comparison of the Conventional 50, which is another configuration that's in the model, an Advanced 200, which would be a two LMS100 turbine. We decided to pick a two, a two turbine set just to stay consistent with the two. We've been seeing, we've got siting cases now, five or six with LMS100s. And we've got anywhere between two and eight being proposed, I guess the eighth isn't in yet but it be in any time. So any number of configurations will be happening with the LMS100s.

And I believe I am giving it back to Joel. So if there are any questions on how the data was either gathered or used?

MR. KLEIN: I don't know if I'm the most qualified person here but I'm willing. This shows the data that Will gathered for fixed and variable O&M. Combined cycles on the top, simple cycles on the bottom. If you looked at the fixed O&M, the upper left hand quadrant, it shows the fixed O&M is assumed by us to be a sum of two quantities, staffing costs and non-staff costs.

We have actually seen fixed O&M assessed at just being staffing costs only. We think it's the more common practice to have them both together. And you're going to see different, different techniques of -- different people will put different quantities in variable O&M but this is our standard.

On the right I just show the single curve for the variable O&M because actually it's a function of many components. It makes sort of a mess out of the graph. But the large one -- and most all the cost is just the scheduled O&M, which would be both the annual maintenance and the overhauls. There's other much lesser costs in there such as consumables, environmental equipment costs, water costs. Have I missed anything?

MS. REDNAM: Forced outage.

MR. KLEIN: What did I hear?

MS. REDNAM: Forced outage. Unscheduled maintenance.

MR. KLEIN: Oh yeah. There's also a small amount for forced outage, it's very small. It's not pleasant when it happens but apparently it's not a large part of the costs.

Something we didn't show you in the model is that we have assessed these values for fixed and variable O&M but the model is set so that you can go in and override. If you feel you have a better value for a fixed or variable O&M you can put that in the model, which cancels out a large part of these calculations. So if somebody has better data or data they prefer to use they can certainly use it.

Okay, now here is something I'm not going to spend a lot of time on but it's possible to spend all day on. Heat rate degradation. Due to the fact that the units operate and they wear and tear, eventually the heat rate slowly degenerates and there's different data out there.

The data I've used, which is rule of thumb, which is sort of an average like, you know, value. It's just applied by rule of thumb. Is that the combustion turbine, which is the driving part of the unit whether it's a CT or a CC, about 24,000 hours it has to be, it has to be overhauled. So you never reach anywhere near that with that if you have a simple cycle unit. So in 20 years this thing would go to 55 years. So we have a rule of thumb from them that it gets about .05 percent per year and that's what this graph represents.

Now the CTs are a much more complicated proposition. It's going to reach its 24,000 hours just short of five years. But to make this graph simple I did it five years. So you see the degradation is going up, you have an overhaul, it drops down. The degradation goes up again, you have an overhaul it drops down. What happens is the CT itself will degrade about three percent but that is only about two-thirds of the overall degradation because the actual steam portion of that is not degrading significantly.

So you take two-thirds of three so more or less it goes up two percent, drops down four-thirds of a percent and so forth. And I just draw a line through that and I get the .2 percent per year.

Now again, this is a lot of attention to something that's relatively insensitive in the model. Even for the CC here this is maybe two percent. If you have any number in there at all you're within one percent. But nevertheless it seems like we get to spend hours and hours discussing exactly what this is and I already feel like I've spent too much time on it today.

But for those that will ask. And we

have a lot of things in the model simply because people will ask. We're already getting questions on this item.

ASSOCIATE MEMBER GEESMAN: So how did you validate your rules of thumb?

MR. KLEIN: I accepted what General Electric told me with blind acceptance. They have a document out and I accepted that. I think there is actually some more recent data that we're looking into. I figured GE is the experts, I'll take what they give me. Plus, again, it's very small.

Okay, we'll talk later about whether you measure this as a busbar or the load center and these are the factors that we used to capture the losses. And this went through the CPUC MPR proceedings. It's sort of a small matter so I accepted something that had undergone scrutiny and been accepted so I wouldn't have to suffer through it myself.

Now here is something I thought might be interesting. I compared levelized costs we're getting in the present IEPR to those that were reported in the 2003 IEPR. Now this is -- There are so many things that are different. This is not easily done. But if it's not completely informative it's at least always interesting. Now these are numbers. Graphs are always better for me. This is just the levelized cost comparisons.

I eliminated a number of them because they just weren't similar at all and I think there are some questions here, even on the solar thermal Sterling but I can sort of rationalize those. But in the interest of time I picked the one which I was most familiar with, the simple cycle unit, and I tried to explain why do we have differences, why are these so different. And I think this one is particularly interesting because things have changed dramatically.

Okay, the first thing I did is recognize that whereas the 2003 IEPR had assumed a capacity factor of 9.4 percent we could find nothing, and I had Will look at this extensively, to suggest it could be over 5 percent. Even trying to, you know, extrapolate in the future, which one can only guess at. And that brought our present levelized cost of $586.36 down to $350.48. Again this emphasizes the point. If you don't know what capacity factor you're talking about you can get all sorts of numbers.

Then I compared fuel prices that we're using now as opposed to what they used in the 2003 IEPR and it jumped down here to $331. The installed costs you see are twice what they were. So if I use their installed costs it goes down to $243.56. Based on talking to Will they were always probably around $1,000, just nobody knew it. We were getting AFC prices that looked like this might be reasonable but it's just another reason that you can't rely on AFC prices. Then I changed the capital structure to the old capital structure and I got $219.65.

Well I get down to where I'm pretty close, you know. I can explain a lot of it. But in the final analysis there's so much difference in the way we're doing taxes now as compared to what they did then or the model itself I cannot hope to explain you know, that last 40 buck there. But I think I have made a somewhat reassuring attempt there to rationalize those differences.

Now here is another thing. I thought, well it's interesting to see what sort of numbers the EIA has or some other entity. And we've done some other comparisons but I decided to only bore you with one. If you look at the simple cycle, for instance, and you look at the instant cost, which is what they publish, see we're having $925 and they're having $447.

So there's a lot of approximate, in my opinion, not accurate data. Now we do have some higher costs in California that they don't have and they probably don't include linears. This is all the transmission, water connection, gas supplies and all that stuff. They don't have the ERCs in there so we probably have some numbers they don't have. But I think when you want a number you want the number that has everything in there.

If you come over here and if you come across that line you can see they estimated the capacity factor at 30 percent. Again, we just don't see where that can be over five percent. I think I have some -- Let me come back to that later but I'll show you what we have for the capacity factors in just a bit, rather than jumping over to it. So without belaboring this slide, it does tell you that if we just go out and grab EIA numbers it's just not going to work for us, you know. We really do need better numbers than that.

Now just, just to see the effect of tax credits. Not to belabor the point of whether they should be there or anything. The intention is to show the amount of tax credit. To try to get validation for others to look at this who believe that what we have done is reasonable.

So you see the red part there is the actual tax credit. If you come back to the end of the blue right here, that's the cost with the tax credit imposed. Without the tax credit you'd be all the way out here. So Solar PV it looks like it's getting a pretty good one.

Okay. I've talked a little bit so far about the misuse of cost of generation estimates and I want to belabor this just a little bit more. Whenever you get an estimate it's for one set of assumptions and I think you have already seen that today, you know. It's for a certain equipment cost, capacity factor, location, estimate of linears, ERCs, those sorts of things.

The other thing to realize is you can't predict how this unit that you're thinking about building is actually going to operate in the system. You may think it is going to operate at a 20 percent capacity factor, maybe it's four percent or one percent capacity factor if it's a CT. You may think a CC is going to operate at an 80 percent capacity factor and a lot of people do. It seems to me back here EIA has 87 percent. We've got 60 percent.

Comparing levelized costs themselves. Now we provide these graphs, everybody wants to see them. But this is problematic and it generally leads to drawing the wrong conclusions. You can't just look at the levelized cost of one technology to another and say, this one is cheaper. If you try to, for instance, to compare a combined cycle unit against say a geothermal unit. Well a geothermal unit is baseload.

A combined cycle unit is just operating primarily as you've seen in the peak hours. So what's operating the rest of the cost, I mean, if you're trying to compare those two. It really should be the geothermal unit against the combined cost, the combined cycle and whatever else is running.

This is difficult to do abstractly although we attempt to do these things. The way you get a handle on this is you run them through a production cost or a market model. You actually see how the units run and how they compare. I've seen myself cases where it looked like one technology just wasn't going to compete and it was a winner. And then the bottom line is, always remember, the cost model and the market sim model isn't perfect either.

But the way you should do this planning, you start out with a levelized cost of generation estimate, put it in a screening curve, look at the screening curves. Maybe you can screen out units that obviously aren't compatible because they're so far out. You put it in the production cost model and then you go from there. This selection of technologies or these studies are not a one-stop process as people try to do.

Okay, I'll belabor this just a little bit more to tell you how we've tried to overcome some of the limitations of the model as best we can. The model is not perfect but we think it's one of the best. Okay, we've talked about the --

Here's four factors that probably drive the results as much as anything. Capital costs, well you've just seen Will belabor the effort we went to to try to improve those.

Fuel costs, I throw up my hands, you

know. I don't know. Talk about unpredictability. Here is a slide that shows various forecasts and what the actual costs, of course these are wellhead prices but it still makes the point, that actually occurred. So I think this is extremely difficult to -- And thank God that's not my job.

ASSOCIATE MEMBER GEESMAN: Were those in constant dollars or nominal dollars?

MR. KLEIN: Oh my golly gee. No. My expert tells me no.

ASSOCIATE MEMBER GEESMAN: So they're nominal dollars?

MR. KLEIN: Yes. That's my recollection too. Okay. Capacity factors is another issue. We tried to improve that, you know. I've just been over this. Whereas many are showing combined cycle units to be around a capacity factor of 90 percent we got it down to a more realistic 60 percent. Simple cycle units we got down to a more realistic estimate of around five percent.

We're using screening curves so we can actually see how these things vary with the capacity factor. So we think we're providing information for people to make much more intelligent choices. To say nothing of our sensitivity curves.

Now these are just more capacity factor curves. We've seen enough of those today. Here are the actual capacity factors that I promised you. We went through and for 2004 and 2005, I think Will actually compiled this data.

And these are how the capacity factor units are actually operating in the field. And this, by the way, is generally comparable with what we're seeing in our market sim model. These things are just not on average running above 60 percent. I've heard more recent numbers of people telling me they're going to be more around 55 percent. Again, 90 percent is not a good prediction.

Here's CTs. Here is some work that Will did. These are simple averages. Actually I think it's a little worse if you use weighted averages. You see there's not much to suggest there that on average these things are going to be running at ten percent or even above five percent. These are generally some low numbers. Here is an exception.

Okay, how much more of this? Okay. Another thing where they miserably fail in these models is in estimating heat rates. We have tried to improve on this by actually looking at the QFER data and constructing heat rates, the actual operating heat rates, so we have all those starts and stops and ramp-ups and ramp-down. And we really feel that it's a much more accurate way to get an average heat rate so you can develop an average cost. So that's another thing. We may not have gotten everything but we're getting everything we can.

Okay, next steps. Lorraine, are you back there? Well we've been through this before. So this is going to be, it concludes our presentation for this morning. Anybody else? Will? Richard? No? Okay.

So again just to reiterate, and I guess we'll do it again at the end of the day. We're trying to get written comments by June 22. We're take your comments and we'll issue a final report by the end of July, hopefully a little earlier. And we hope by that time we'll have posted the model and the users guide. We hoped to have the model and the users guide on-line before the workshop but the forces were against us, the black forces. We'll get that done just as soon as we can.

So much to my surprise it's 20 minutes to 11 and I guess it's up to -- it's the Commissioners call what you want to do next. Do you want to go on to this afternoon's presentation, break for an early lunch or what?

PRESIDING MEMBER PFANNENSTIEL: Should we see if there are comments from the audience, from the public?

MR. KLEIN: I beg your pardon, absolutely.

PRESIDING MEMBER PFANNENSTIEL: Questions or comments on the model that we just heard the presentation on?

MR. KLEIN: I apologize for that oversight.

MR. McCANN: One thing that I think was brought up when there were a couple of questions about various plant configurations. The model actually automates the plant configuration based on location. So we have -- The model is set up so that it has, how many, seven regions I think approximately. South Coast, San Diego, the desert region, et cetera.

And the model will actually choose different plant configurations that are appropriate for that particular region. Including, for example, the gas prices, air quality emission prices, whether it has a chiller on it or not. So that those sorts of things are automated in the model so that you can pick a particular location.

What we were representing there as a base case, that's a California average, which is one way of doing the model. But we can also, the model is set up to do it by service area, for example. You can have a PG&E configuration in the Bay Area and the model will give you a result that varies by that within the model.

So there's certain components of it that you can actually look at more specific configurations and spit that out so that we, that can address some of the issues that you had about whether we need to have recycled water or not in that configuration. That will often kick out of the model.

MR. KLEIN: For instance if you set it for the South Coast you get much higher AR.

Okay, questions from the audience, please. And if you have a question would you come to one of these two microphones. Are these both hot?

MR. WANLESS: My name is Eric Wanless and I work with NRDC and I am also speaking for the Union of Concerned Scientists today.

I guess my question or comments that are related to this morning's topics are related to -- I guess especially in looking at the sensitivity analysis that you can do with the model, which I think is a very pertinent and a great addition.

I'm curious if there is any I guess attribute for carbon cost in there in running those sensitivity analyses? I think in reading through my impression that I got was that only the ERC costs are kind of taken to account. But I think it would be very valuable to have some sort of toggle for carbon costs, especially because people are going to be using these numbers in AB 32 implementation work. I think that's something that would be very handy in there. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. KLEIN: Okay, thank you.

MR. NELSON: Good morning, Mark Nelson, director of generation planning and strategy for Southern California Edison. As a recovering econometrician it's always fun to watch modeling but I've been out of the business for awhile.

I had a question about the wholesale prices. Is your estimate of wholesale prices the same for every technology because it's an estimate of wholesale market price? Or is it sort of thought to be the wholesale price that that particular technology would sell into the market as?

MR. KLEIN: It's a very simplistic technique. I assume that despite everything that might be going on, in the on-peak for instance you might have hydro on, you might have a peaker on, I characterize those fixed costs as simply a combined cycle unit running. And I've looked at the model. If you look at the fixed cost to some degree the peakers and the hydro tend to somewhat cancel each other out so it's very simplistic, you know. That's how I get the fixed cost.

The average cost -- excuse me, the variable costs, are from the market sim model. So they're as good as the market sim model itself. So whatever it's generating is the average weighted cost of a gigawatt hour in that model averaged over the year. I just did this averaged over the year. That's my price.

MR. NELSON: So you've got, so you do have the same wholesale prices irrespective of technology.

MR. KLEIN: Yes.

MR. NELSON: So you are forecasting the wholesale price of the market.

MR. KLEIN: Yes.

MR. NELSON: Okay, thanks. And then I've got, you know, data people obviously who will look at the data and as soon as the model is available we'll ask financial people to take a look at the model as well. Just a couple of comments I had.

From a cooling perspective as I look into the future I see potentially more use of aquifers with, you know, high total dissolved solids, non-potable water that will require cleanup. And that type of water may turn out to be more expensive than, it may turn out to be more expensive than wastewater. And depending upon the distance you have to pump the wastewater it still may be a good investment. Again, it's hard to tell at this stage. I think everyone is weighing the difference between wet cooling, dry cooling and some sort of hybrid coolings.

Linears seem to be I think, again as we move away from a rear view mirror approach, I think the cost of linear seems to be increasing over time. Again, as we get further away from existing infrastructure. And I guess that's not a big surprise. Again, we're not building much inside of highly urbanized areas.

I did notice that advanced coal and nuclear were both in the Navigant presentation that presumably I think we'll see this afternoon.

MR. KLEIN: That's correct.

MR. NELSON: But haven't appeared here yet.

MR. KLEIN: Well all we showed this morning was a summary of the inputs and the outputs for everything. But as far as the details, that will be this afternoon.

MR. NELSON: Okay. But I guess, I guess just in the overall chart. I just didn't see either the advanced coal or the nuclear. And I could, I could be mistaken, it might be my --

MS. REDNAM: Yeah, they are there.

MR. NELSON: -- my +2 reading glasses.

MR. KLEIN: It's there, let me see.

ASSOCIATE MEMBER GEESMAN: I saw it on the tax credit chart.

MR. KLEIN: This won't make you feel any better but we'll show it to you.

MR. NELSON: I'm closer now.

MR. KLEIN: That's help.

MR. NELSON: I might have a chance to see it. There we go, I'm sorry.

MR. KLEIN: There. Can you see the --

MR. NELSON: They are there, okay. I just missed them.

MR. KLEIN: It's a lot of data and I apologize for that. It's dense. That's why I tried to use graphs to help a little bit, yeah.

MR. NELSON: I'm an econometrician, data is good.

MR. KLEIN: Okay.

MR. NELSON: It was our life blood for awhile. And then I guess the last comment I had was I think we've seen a movement on CTs away from frame machines and to aeroderivatives, you know. And if you look at the EIA chart with the 160, 180 megawatts for a CT you know they were thinking frame machines, big machines instead of smaller aeroderivatives. And that I think is a larger driver of why the costs appear to have doubled. And what it really is is a change in technology, choice, you know.

And I don't disagree with the change. I mean, I think a lot of us are still questioning whether you can, whether you can make NOx with a frame machine as a CT. You know, hot SCRs are a lovely concept but not well proven in the industry. So still working there.

MS. REDNAM: We have captured both the aeroderivative ones and the simple, the standard ones too in the model.

MR. NELSON: Okay.

MS. REDNAM: We have them.

MR. NELSON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Further questions or comments?

MR. KLEIN: Anybody else? One more brave soul.

MR. MILLER: Hello, I'm Tom Miller from PG&E. First I wanted to commend the CEC. I think it is a very fine tool, a very instructive tool that you're developing and we have a lot of interest in it. We will be preparing some written comments but I will take the opportunity.

One of the quick observations we had was that regarding the capital costs of a simple cycle, the CT versus, you know, the combined cycle now seems to have flipped where a CT seems to be more expensive just, you know, with capital costs and isolation. And I was wondering, given that the information, the data that you're looking at is confidential and everything, did you see any observations of trends in capital costs or anything that could explain that, that difference?

MR. KLEIN: I think that would be a Will question.

MR. WALTERS: No, I didn't really see anything in transit. I think the biggest difference probably is in the design, in the base design that we are typically seeing in California. I think that the previous commenter kind of hit on the difference between a larger frame and the aeroderivative turbines in terms of the total cost. In terms of the ranges of costs they did overlap a little bit but the lowest of the CTs was still in the very high end of the range for the CCs. We really weren't seeing any way that the average could be anywhere near the way it was presented previously in the opposite manner.

MR. MILLER: The other discussion we've had here is, you know, the cost of fuel and natural gas of course, you know, being very volatile and I was wondering what your thoughts are. The capability of providing perhaps a range of natural gas forecasts that might be able -- the user could select.

MS. REDNAM: We don't have a range of forecasts in the model.

MR. MILLER: No, I know at this time but I think, I understood that you were waiting for an updated IEPR forecast.

MS. REDNAM: Fuel price, yes.

MR. KLEIN: Well, it's my expectation that at some point we will get a range of gas prices. But I am not familiar enough with that to speak to it with any certainty. Al, do you know anything on that? No? No, Al doesn't seem to know either. But in any case you've got a point.

MR. MILLER: Okay, thank you very much.

MR. KLEIN: And that's something we generally try to do is to have a range of gas prices.

MR. MILLER: Thank you.

MR. KLEIN: Thank you for your comments.

PRESIDING MEMBER PFANNENSTIEL: I think if there are no other comments on this presentation I propose that we move right on to the discussion of alternative technologies.

MR. KLEIN: Excuse me. Would it be -- I think we should probably go to the people that are Web-Ex. Would that be okay?

PRESIDING MEMBER PFANNENSTIEL: Are there people there?

MR. KLEIN: Yes. Okay, anybody out there on Web-Ex? If you have a question speak up.

Going, going, gone. Okay, that was an unnecessary exercise I guess. Okay. So where do we go next?

PRESIDING MEMBER PFANNENSTIEL: Move on to the discussion of alternative technologies.

MR. KLEIN: The next presentation, okay. Sean, can you come up and do your thing. Are you going to start first, Peter?

MR. SPAULDING: Yes, I'll just introduce Sean.

MR. KLEIN: Okay, Peter Spaulding will say a couple of introductory words.

MR. SPAULDING: Thank you, Commissioners and audience. My name is Pete Spaulding, I'm with the energy generation research officer of the research and development division, I work in the PIER program.

And we contributed to the cost of generation model by developing cost inputs for a variety of renewable technologies as well as the advanced coal and nuclear. And in order to develop those cost inputs or inputs to the model we retained the services of Navigant Consulting, Incorporated. Navigant put together a team who did extensive phone calls and contacting the industry to develop these inputs and then those inputs were reviewed by our PIER staff.

And I just want to say that the Navigant team consisted of a number of folks that were headed by Lisa Frantzis who is their director of renewable and distributed energy who has worked for 27 years in managing market and economic analyses of renewable energy systems.

And the team also consisted of Jay Paidipati, who also is a senior consultant in the strategy and management group. He works in the areas of renewable energy and energy efficiency and has focused on renewable technologies and efficiency standards for appliances.

Also on the Navigant team was Ryan Katofsky and Ryan has particular expertise in biomass energy with 13 years of consulting experience and has worked on a number of renewable energy projects.

And then those folks were supplemented by our PIER staff, which includes Gerry Braun, who is our renewables lead, Valentino Tianco who, dealt quite a bit with the review of the model as well as the tax incentives and the importance of federal and state taxes, which were pointed out this morning that were so important to the model.

And then also our PIER team, which included Mike Kane looking at wave and hydro, Dora Yen on wind, Art Soinski on fuel cells, Golam Kibrya on solar and Zhigin Zhang on biomass.

Most of the work -- A lot of the work done by Navigant Consulting was performed by Sean Biggs. And Sean is with us today to go over the approach that was taken and to briefly talk about on a broad perspective the different types of technologies that we looked at.

And unfortunately I didn't get Sean's bio ahead of time but I do know he's a graduate of MIT and has successfully completed at least three

Boston Marathons, which carries a whole lot of weight in my book. So I'd like to introduce Sean Biggs.

MR. BIGGS: Thank you. Hi everybody. Can you hear me well? Hear me better now? Excellent. Yes, my name is Sean Biggs. I have been working with Navigant for several years. I sort of managed the process here. And we'll get some of the other folks on line.

As you'll see we -- I'll go through sort of how we got to this point of getting the results, which is actually, given sort of the background of renewable energy today, is a bit challenging. As going through the combined cycle and the simple plants, you know, there's been a lot of changes since 2003 and they did a very good job of capturing that.

For renewable energy you also have the challenges of these technologies are changing quite a bit. They are fairly immature technologies, there's a lot of R&D going to these. And as more and more attention gets placed on these as well as more gets put into the field people get better at this. They get cost reductions just from learning. So we're trying to capture some of these dynamics in our numbers.

I will be able to hopefully get Lisa, Ryan and Jay on the phone. They'll be able to, after I go through some of the approach, they'll be able to answer a little bit more of some of the technical details. But what I wanted to do before I went into the presentation that we have -- Because of what we have is very sort of specific cost information as well as a rationale for how we go there.

But just to sort of put these things in context, I think if you look back to 2003 when the 2003 IEPR was put together not as much attention was being placed on renewable energy and not as much was being actually put in the field, especially in the United States. But with $3 gas prices and not as much emission costs, not as high of incentives, you know, that sort of made sense back then.

But since then as everyone knows because it's in the paper and on the news almost every day, renewables is sort of hot. And also as sort of California being sort of a leader in this area knows, you know, these are more and more becoming a more central part of generation strategies.

So what's happened as a result of that is costs have continued to improve and performance has improved for these technologies. But as more an more attention is being put onto these technologies actually some of the costs have increased.

Just looking at wind and solar, wind costs about $1,200 a kilowatt back in 2003, which we're fairly confident that that was the cost, but today it's more like $2,000. Because there just isn't enough turbines, there's not enough labor to install these, steel prices have gone up and most of the material is steel. All those things contributing to the increase in prices.

With silicon on the PV side costs have gone up because there hasn't been as much silicon manufacturing capacity and that takes two or three years sort of to build these big plants and then come on line. So that's sort of driven up costs on the PV side.

So, you know, what we're trying to do, and I commend our colleagues at the CEC. What we want to do is really have a justified sort of data for all these assumptions. So we want to go back and say well it's this public study that surveyed these costs. Or it was this CEC data that shows costs for installation in California.

But that's not always easy because if you go back to even just some prices in a public study in 2005 that was done it might say, solar cost X and everyone in the business knows that it costs, you know, not X by Y. So in trying to get that we've had to sort of come through a process to triangulate to get to some of those numbers.

With that let me just -- This talks about our process. What we first did is we tried to review the relevant literature, whether it's an EPRI study, a CEC study, other published data. So that we could really get an understanding of sort of the best published data that was out there as well as what type of facility will actually be built in California.

You know, for example, looking at the potential landfill gas sites in California suggests that you might actually have on average more -- you know, new facilities might be more like one megawatt when actually existing facilities are more like five, even to ten. So in developing our cost estimates we want to do the cost estimates for something that is going to be more like the one megawatt, which sort of would be the average for what might put in the ground in the future. So we did that.

We also reviewed sort of our in-house data. We do this on a regular basis for other clients. We have our internal database that are comprised of -- also published literature, also other consulting work that we do whether it is a generation strategy for a utility or a technology due diligence for a venture capital firm that's looking to invest in one of these new emerging renewable energy technologies. Or, you know, an engineering, a textbook that, you know, describes how these things operate.

So with that we developed our sort of initial straw man data that we thought reflected current data as well as something that was appropriate for California. We took that data and submitted it out to the people we thought would have a good sense of what the market is in California today. We conducted interviews with those industry representatives and asked them if our assumptions were appropriate and with that we came up with some draft data that we reviewed with CEC. And then we sort of made sure that with the

CEC, with other experts within Navigant, and then putting all of our technologies on the same page whether it really made sense.

At the end of the day I think we've got technology costs and performance assumptions that we can go back and say, yeah, that is based on this data or this study or these interviews and we feel confident that we have got a good baseline of data. That to be said it is important and I'm glad that we have public involvement here today because there is always, we always learn from forums like this so we're also looking for feedback as well.

The other comment I think I just want to make sort of as a challenge in developing these cost estimates is that not all of these technologies are at the same level of maturity. Some technologies, large, large-scale wind, people sort of understand. There is a lot of experience with that today. It's a fairly mature technology, even though there is still a significant amount of potential for cost reductions.

There's other technologies that are maybe just as mature, even more mature. Take a landfill gas site. Very mature, it's been around for a long time. But cost data that you might review that is publicly available, maybe it's from 2003, maybe it's from 2004. Maybe that doesn't reflect some new costs that are required based on emission regulations. You might need a higher gas cleanup costs or emission control costs. So it's important to sort of try to capture all these.

Some of these technologies though aren't as mature. In those situations you might have engineering cost estimates or you may even have just a pilot plan sort of as your data points. You know, I think part of what we did with the CEC is to make sure that we were taking those types of data points and creating sort of a consistent for a level set of data points because there are sort of some pitfalls I think that if you didn't sort of do the sanity check across all the data points you might run into --

For example, an engineering cost estimate might be a bit optimistic, it might not capture some of the difficulties that are often encountered when making something actually commercial and operational, whether that's some of the actual additional data in terms of linear costs or financing costs. And the CEC process and the modeling approach I think did a very good job to make sure that we weren't leaving out some of that data.

But on the pilot plant side you might actually get something that's a little bit higher. A lot of these pilot plants, they sort of over-engineer the system so that they can test all these different functionalities.

But really in reality when you actually built something it wouldn't necessarily have all that functionality and it's probably a little maybe smaller so you want to make sure you get the cost estimate for something that would be not necessarily a pilot plant but maybe something that would be built. So trying to take all that into consideration is sort of the process we went through with our colleagues at the CEC.

What I'd like to do before I go into actually -- There's about, there's quite a few pages here about, we basically put together almost four pages for each technology and there are, I believe, almost a dozen sort of technology categories and several technologies within each of those. So instead of going through individual pages, because I'm afraid I'd be jumping back and forth, let me first tell you sort of the structure of those pages.

First, one page just gives the basic description of what it is and what we're trying to capture. So for example, you know, when we're talking about a biogas from animal waste we mean a certain type of digester that takes the animal waste and converts that through an anaerobic digestion process into biogas. There's many different forms but we sort of specified which one we were talking about so that it would be clear, you know, what our costs estimates are based on.

Then we basically have two pages of both installed costs, capacity factors. Sort of the meat. And in each one of those we spell out where our sources came from and how we came up with what the source is.

But then on the fourth page what we try to do is, because it's not always easy to specifically say, well okay, we assume $1900 as the installed incent cost for wind and we used these sources. But how did we really weigh, you know, these different sources. So we included a fourth page that we tried to give you a little bit of explanation of how we weighed those different factors. So through all of that we hope that that document is helpful for you to understand how we got to our numbers.

But what I think I'd like to do, and I'll let Pete sort of guide me based on any other comments. But what I first want to do is I just want to run through the different technologies that we have here. As you see there's 104 pages. I won't go through them all. What I'll do is I'm just going to list out the technologies, give you a brief sense of the key data sources that we used as well as sort of the thinking behind the nature of the markets today as well as some of costs that we had.

If you look at biogas initially there's four technologies that we looked at there. There's landfill gas, there's wastewater treatment plant, there's animal waste sources and food waste. Landfill gas and wastewater treatment plants are fairly mature. They're quite pervasive here in California as well the rest of the United States. Fairly mature technologies.

But as I mentioned before, there are some new requirements for these to include gas cleanup and emission control in many of the areas of California. And so we, a lot of the changes in those costs are based on that as well as there is a small sort of increase in terms of commodity prices as well.

The animal waste technology. Again, that is also something that is fairly mature and cost data is actually fairly well available, both through CEC documents as well as Wisconsin and Cornell University have put together a lot of survey data that says there's 40 different plants built in California or Wisconsin or New York and this is what the total costs were. We went through that and made sure that we aligned it sort of towards one technology and to California. And then what we did is we took that data and confirmed it with the industry.

On the food waste side, that's a bit more of a new technology. It's something that actually I've seen, you know, the CEC doing some good work at UC Davis. They've got a pilot facility there. And there's also a lot of work in Europe. There's different sort of types of technologies that are sort of competing to win here and so what we did is we took our knowledge of some of the facilities that are in Europe as well as talking to some of the folks at UC Davis to base our numbers there. But again, that is not as much of a commercial technology.

From the biomass combustion side there are basically two, the fluidized bed and the stoker boiler. And those are relatively mature technologies compared to the rest of these. There's a few cost studies done by Oak Ridge and NREL as well as the CEC. And we were able to take that data and confirm it with folks in industry. These are also cost data points that we have internally that we were able to confirm those numbers.

With the biomass gasification, that's sort of a, the actual application there isn't as, there's really no commercial facilities. There's sort of one pilot facility in Europe that has sort of proven the concept. But in general this technology is sort of putting actual mature technologies together.

The gasifier, we know that works. And the other technologies, these work. But putting it together and actually making the biomass gasification plant work is -- you know, the cost of those are really more based on sort of the engineering cost estimates and discussions with NREL as well as sort of our internal cost estimates.

On the geothermal side. Again, this kind of goes to a technology that is a bit, it's definitely a more mature technology and a lot of experience within California but the question is, what will be these costs in the near term in California on the existing sites. So what we did is we took some of the CEC data as well as some of our internal data and put that in front of some of the leading manufacturers of the equipment as well as the developers of the projects to make sure that we had the right estimates there.

On the hydro side, again that's a bit more of a mature technology. But that's a technology where it varies so much from site to site depending on how much civil works you have, how much permitting is required, how big of a scale the project is.

So what we looked at, the Idaho National Lab has profiled the feasible sites in California and that sort of brought us up with sort of what we thought might be the typical site. We used some, some cost estimate models that are publicly available and embedded in other public processes to develop the cost estimates for those types of plants. But that's something where it's a bit more of a range.

The same thing on sort of the in-conduit where with the small hydro you have a more typical dam impoundment structure but the in-conduit does not require the impoundment structure. And NCI, Navigant, we did a study estimating those costs for the CEC just about a year ago and so that was the basis of those numbers.

Concentrating solar, that is something -- those are -- a lot of work has been done recently to develop the cost estimates and we have been involved in a lot of those. Arizona has sort of a road map trying to really get off this industry. We helped them look at those costs, talked with a lot of folks in industry and NREL to develop those, both for the concentrating PV, the dish Sterling parabolic trough and power tower technologies. So the concentrating PV and the dish Sterling technologies really primarily on that Arizona road map study. And although, you know, we were I guess -- We just finished that study early in year we went back and made sure that nothing had changed in a few months.

On the trough side though, that's a -- probably right now I think it's fair to say that most of the plants that are going in are really looking at a lot of these trough technologies. There's a bit more richness in data there. CEC has some good reports. NREL has looked at this extensively. Black & Veatch, an engineering firm, has really done a nice analysis laying out sort of the detail of the costs and where all the costs come from. Again, we reviewed that in the Arizona solar road map study and then, you know, we put that together to confirm, to make sure that -- again, we do this for each technology to make sure that the costs are appropriate for what you would see in California.

Lastly on the concentrating solar was the power tower technology. There is a facility that's gone in in Spain and there's some studies that look at that that we were able to use as well.

On the PV side that's a bit more straightforward as California collects data on what's been installed and so that's a matter of looking at that data. We look at this all the time. We have -- We have our own internal database and so we put those in front. That data in front of two industry representatives that indeed we had sort of the most recent cost information and that nothing had really changed. Because again, as silicon prices change and other market forces change the prices do change, annually at least.

On the wind side. First at the small wind. That's actually sort of, it was a fairly easy -- Again, with California's DG program they track the costs there. Eighty-six percent of the small wind facilities are a ten kilowatt system produced by Bergey Windpower and they all have the same sales price. The one thing we did when we called up Bergey Windpower is we said, actually the CEC has sort of made a double-counting error on actually what the size is. It actually is a ten kilowatt, not as posted as a nine kilowatt on the website. So we corrected that to make sure that we actually got the cost per kilowatt correct but that was fairly straightforward.

The large scale wind which is, you know, a fairly sort of hot topic. Sort of everyone wants to talk about, what does it actually cost.

Because just, you know, a year ago people would have told you something that's vastly different from today versus three years ago. We've seen it, you know, move from $1200 to $1400 to $1500 up to, you know, basically $1900 to $2000 that are all in costs. That, again, I think most people in the industry are quite comfortable with that number.

It's taken many people some time to get comfortable with that because someone just built the plant a year ago when it was much cheaper so not everyone is as comfortable with that. And also there are, there are variations. Not all these wind turbine facilities are the exact same. Some have 60 meter towers, some have 80 meter towers. So, you know, more towers is obviously more difficult to -- it has more materials, a little bit costlier. So we did, we were able to come to a consensus with industry and other folks there.

Fuel cells. We only really -- Fuel cells, we only looked at fuel cells using renewable fuels and the primary renewable fuels we looked at were the biogas coming from landfill gas and wastewater treatment plants. So we were able to -- So what we did is we based those cost estimates on, you know, similar assumptions as if you were building the landfill gas and the wastewater treatment plant with our biogas.

So we looked at sort of the same sizes, a one megawatt for landfill gases and the 250 kilowatt for a wastewater treatment plant. Because those are kind of the average size of facilities in California that are looking to be, to be built. But what we had to do is look at cost estimates from NREL and DOE. They've had an extensive process of trying to vet out what these costs are going to be.

We also looked at some of the test facilities that have gone in recently using some of the carbonate facilities technology. And we also made sure that, you know, we converted some of these technologies to make sure it was California specific as well as renewable fuel specific because a lot of the cost estimates are based on natural gas as a fuel.

Wave technology. Wave technology is catching a lot of attention recently. This is a technology that there are really no commercial applications. There are several pilot facilities in Europe, Portugal and Scotland are looking at this quite a bit. What we did -- And also EPRI is really on top of this, they've developed some good cost estimates. As well as Portland is -- Oregon has looked at some resource assessments on exactly what type of capacity factors you could get for the West Coast of the United States. We looked at those estimates, really sort of vetted them with EPRI, and also vetted them with some of the industry representatives to get what maybe a first pilot facility would look like in California.

Lastly, coal and nuclear, which was mentioned earlier. These are, these are technologies which, especially on the nuclear side people are more familiar with but the actual cost of what's going to go in, that's, there's a bit more uncertainty there. The approach that we took is we wanted to base these cost estimates on published studies. There are several published studies that we thought were quite good benchmarks, although they weren't necessarily specific to California so we needed to -- not as necessarily specific as to today's prices relative to commodity prices.

So on the clean coal side MIT just published a study to confirm some of our numbers, although it was published after we did this work. But the Wisconsin PUC actually looked at the IGCC clean coal technology and there is a very detailed report of what something like this could cost in Wisconsin. Now a lot of the folks that we were talking to thought that it would be a little bit higher in California so we took that into account.

On the nuclear side we also looked at an MIT study. They looked at the nuclear activity around the world, whether it's Japan, South Korea, China, Finland, to really sort of base their numbers. Again that was a bit of an older study. It doesn't account some of the cost increases in commodity prices.

That all said, you can hang your hat I guess if you will on some of those studies. But it is not going to get anyone comfortable, I guess, with the idea of what it would actually cost in sort of California in the future.

I say that with a bit of a disclaimer because, you know, we work with utilities who are looking at this. You know, when you really get down to dollars and cents for someone who is serious about, about building one of these then, you know, the very first ones are going to need to go through a little bit more public scrutiny. They're going to be the first of a kind in many years for nuclear and first kind on a really commercial scale in the US on the IGCC. So that cost of a first plant would be here and then as you get better you're going to come down with learning, theoretically at least.

Now what those costs are a bit more based on sort of an opinion in judgment. And we did not decide to go with some of those estimates because, one, we didn't see California as necessarily being the ones to lead the charge on these technologies as being sort of the first ones to put in nuclear or IGCC. There's plenty of other technologies that are -- I should say projects that are being planned right now that probably are going to be more at the higher cost. So this is more of a longer term cost estimate for California.

With that I'd leave it open for questions and then we can go specifically to the pages. We can bring in some of my colleagues to maybe give a little bit more color on some of the details of the technologies and how we came up with the cost estimates and performance parameters.

Any questions? And let me confirm if Lisa and my colleagues are on the line. Are you guys there? Did you get a hold of them, Pete?

MR. SPAULDING: Jay and Ryan are on the line.

MR. BIGGS: Okay.

MR. SPAULDING: I have spoken to Lisa. I think she's listening in but --

TELEPHONE SPEAKER: Hi Sean.

MR. BIGGS: Hi there. Good.

MS. FRANTZIS: Sean, the three of us are on at this end, Jay, Lisa and Ryan.

MR. BIGGS: Excellent, good.

ASSOCIATE MEMBER GEESMAN: Did you look at any of the other advanced coal combustion technologies besides IGCC?

MR. BIGGS: No, we did not.

ASSOCIATE MEMBER GEESMAN: What was the rationale for that? The presumption was that IGCC was further along?

MR. BIGGS: No, actually -- Pete, you might want to talk to that, actually.

MR. SPAULDING: That was in our discussions. In looking at the renewables we were asked to add IGCC and nuclear and those were the only two.

ASSOCIATE MEMBER GEESMAN: Okay. And with respect to nuclear. In looking at the experience internationally how did you adjust for designs that could be licensed in the US?

MR. BIGGS: Primarily looking at sort of the MIT study an looking at they thought was going to be the most likely technology.

ASSOCIATE MEMBER GEESMAN: Okay, okay, thank you.

MR. MILLER: This is Tom Miller, PG&E again.

MR. BIGGS: Yes.

MR. MILLER: I do have a set of questions.

MR. BIGGS: Sure.

MR. MILLER: As you go through the different technologies if you could give some insight to.

MR. BIGGS: Sure.

MR. MILLER: And one would be sort of the tax credit variations that you may have used for the various, you know, renewable technologies and, you know, what the basis of those were for.

How you estimated, you know, say fuel costs for the biomass plants would be of interest.

Also, this is another financial question but regarding say the book life, federal tax life and state tax life variations across the renewable technologies. What you used and how they may have varied across the spectrum of renewables would be very insightful. So thank you.

MR. BIGGS: Let's go through these. So you asked about the tax credits. We primarily rely on a few sources there. It requires many different sources in the end. A best place that we usually start is a website called DSIRE USA. I can't exactly remember what that acronym stands for but they do a good job of updating on sort of a biweekly basis all the relevant incentives, both federal and state.

We looked at also CEC documents and relied on them from our CEC colleagues to make sure we had the right tax incentives that were California specific. And that got us the bulk of the incentives.

Ryan I might ask to talk about the fuel costs for biomass. Ryan, do you want to take that.

MR. KATOFSKY: Yes. Do you have a slide that shows that assumption anywhere? I just don't remember what we actually said it was.

MR. BIGGS: We had $2.50 at MMBtu, assumes $40 a dry ton.

MR. KATOFSKY: Right. This is what I start by calling a typical fuel price use. It's going to be, it's going to site-specific as to what you can get depending on the size of the plant and where it's located. But we used $2.50 as a good, it's a reasonable number when it comes to fuel prices. If you could get it for less -- and it could be more. It's not a commodity like coal or gas where there's a fairly well-defined market price.

MR. BIGGS: And lastly you had a question about the federal tax lives and book lives. Under the tax lives we have to just kind of dig through IRS code and make sure you understand where it's categorized as well, you know. We're not necessarily tax experts so we have to go back to our industry sources to make sure that that is exactly the way, that's how it's applied in the field. It's typically also those folks in the field who own these projects who sort of know things a little bit better on sort of the book lives so we rely on that information as well.

MR. McCANN: I'm Richard McCann with M-Cubed. Just to point out, in the model itself on the plant types assumptions page of the model there is documentation in the comments section of each cell on the various tax codes and things like that. So when you look at the model you'll see the location for many of the citations. The IRS bulletin where we got the MACRS life from, the DSIRE website, some other information.

We took -- Navigant passed on to us much of the tax credit information. In some cases we had to do a little bit of refining in order to refine that information. To the extent that we could we documented it in the model and so it's all there.

I mean, in fact there is one other thing that has been added in that is useful for the PVs in that the California Solar Initiative is actually based on the amount of installed solar capacity that's in the state of California. It varies with that, that forecast. So there's an ability in the model to actually put in a different number for what you think a forecasted solar installation is and it will calculate the CSI based on what that, what that expectation is of the installed capacity.

MS. TURNBULL: I'm Jane Turnbull with the League of Women Voters. I must admit I had an emotional reaction when I looked at the covered lagoon digester as being your choice for animal waste. I wish you had been here yesterday for the discussion of the biomass interagency group on biomass technologies. A good deal of time was spent on dairy digesters. Karl Longley, who is the head of the Central Valley Regional Water Control Board specifically raised the issue of salinity in the Central Valley and the incredible problems resulting from salinity.

I'm serving on the Central Valley Regional Water Qualities Economic and Social Implications of Salinity Task Force and we are really looking at the projected problems that are evolving throughout the valley. This whole issue of anaerobic digestion is very important because it is a means for controlling a lot of the wastes that are contributing to the salinity. So as far as I'm concerned I don't think covered lagoons are a good solution.

MR. BIGGS: I was curious if I could ask you a follow-up question. Was there other discussion whether it was a, was that a choice between different anaerobic digestion technologies that another one would be better or did you talk about that yesterday?

MS. TURNBULL: Well my own personal experience is that other anaerobic digestion technologies are more satisfactory in terms of mitigating carbon emissions. The particular issue in terms of covered lagoons is the lining issue at this point in time. The Regional Water Quality Control Board is requiring linings, the dairy industry is protesting very vociferously. And actually a lot of the installations up to this point in time have not included linings and actually that's contributed to the degradation of the ground water.

MR. BIGGS: Yes, very good. Ryan, I'll make one just comment on that and I'll let you sort of chime in. You know, one thing I think in looking at the different options here, whether it was sort of a flow-through tank or other types of more mature anaerobic digestion technology, there are cost differences there that I don't want to trivialize.

But the bigger cost differential and something that we were trying to be sensitive to is the move from more of your standard technologies you see today. And it's the covered lagoon that has historically been seen more in California. Move that towards these complete mix systems that you're seeing at UC Davis. And we tried to sort of anchor two points there in terms of at least cost and performance.

But I guess we didn't necessarily want to imply necessarily that a covered lagoon was necessarily the solution for farm waste. But I do think the costs there are indicative of what you could get at an animal waste facility without combining waste stream or using a technology that hasn't been proven in the field. So the cost ranges should be fairly similar for other, other mature technologies.

MR. McCANN: And I just wanted to follow up on your comment in that one of the things that's useful for this model is in fact to put in a technology that people find, one side finds attractive and others find problems with. Put in that cost, find another alternative configuration, put that.

The model is flexible enough to put in that alternative configuration for the model, come up with a cost for what that alternative configuration is and then be able to look at the comparisons. Look at different narrations and do that kind of comparison. But to be able, to be able to look at different types of technologies and look at those cost comparisons and be able to, be able to do that with that.

MS. TURNBULL: Well, inasmuch as carbon mitigation is such an incredibly evolving concern at this point in time I think that it is also important to look at the, the extent to which there are going to be variations in terms of these technologies with regard to carbon mitigations.

MR. McCANN: Correct, and that's exactly -- This type of template is just a very good tool for looking at that so we agree with that.

MR. BIGGS: Yes, a very good point.

MR. SHANKER: Hi, my name is Gopal Shanker, I'm with R,colte Energy. And this is a question I guess directed to the Commissioners and the panelists.

I develop mostly solar projects in the

wine industry in Napa. A big part of this development is figuring out, letting people know what the cost of not taking any action is. And that basically means that the cost of, in my area anyway, PG&E's electricity is going to go up by a certain amount.

So based on what I have heard this morning I'm wondering if there is -- And I should tell you that the default source that people rely on is the Energy Information Administration's historical electricity price increases for the state of California. Based on what I have heard this morning is there a place that we can get, based on looking forward, a reasonable estimate of how much electricity is going to go up in the state of California?

ASSOCIATE MEMBER GEESMAN: Well we attempt to do that in our Integrated Energy Policy Report, which we revisit every two years. We'll publish the report later this fall, which will represent our best effort at trying to do that. It will probably in all likelihood vary a bit from the EIA. We've got extensive information on some of the historic problems with EIA forecasts going forward in both natural gas and petroleum. We're likely to discuss that in our report as well.

We also have spent some time, and I believe have another hearing contemplated in mid-July, on the portfolio of supply sources that the utilities currently have and their approach to supply planning. We had some criticism as to the methodologies they utilize as being insufficiently attuned to the risk of future volatility in natural gas prices.

PRESIDING MEMBER PFANNENSTIEL: I believe we are holding a workshop on retail price forecasts in the next couple of weeks. I don't know exactly the date on that. Do you know that?

ASSOCIATE MEMBER GEESMAN: I don't, but that stuff should all be on our website under the Integrated Energy Policy Report.

MR. SHANKER: Thank you. And just to follow, is that going to include any, the carbon tax or whatever it is included in these?

ASSOCIATE MEMBER GEESMAN: By November we will have attempted to make some rough estimate there.

MR. SHANKER: Very good, thank you.

MR. WANLESS: Bring my computer up here, my notes are on the laptop. Again, my name is

Eric Wanless and I'm speaking for both NRDC and the Union of Concerned Scientists. I'll just kind of ask the NRDC points that I wanted to bring up and then get into the UCS stuff, which I acknowledge I am not as familiar with so we are going to be submitting written comments as well. So any tough questions I will have to answer then.

In terms of the IGCC stuff, you're talking about clean coal and in looking through the report I didn't see any carbon capture and storage stuff in there. I think that is something that probably needs to be in there, especially if you look at the assumed emissions rate for the IGCC plant that you're looking at and compare it to the --

MR. BIGGS: Standards.

MR. WANLESS: The SB 1368 stuff.

MR. BIGGS: Yes.

MR. WANLESS: You're going to have to have carbon capture and storage in there if you're building those plants for any sort of baseload power. And then just some, you know. I'm sure you'll be able to get numbers for that but just, you know, very broadly speaking, CCS can add roughly $450 per kilowatt insulation costs on top of IGCC. And then really roughly speaking, a dollar and a half per megawatt hour in terms of additional costs.

The other kind of broad comment that I had was you were taking about kind of the current state of things in wind power and solar and how costs are kind of going up. I just want to point out, yes, we have kind of a lot of short-term costs that we may be seeing increases in. But that's also stimulating an increase in the capacity for people to turn out turbines and that sort of thing.

So I think if we're using these numbers, people are going to be using these numbers to compare technologies and people are going to be using them to look into the future a little bit regardless of whether or not we tell them that's a good idea or not. So I think just kind of noting that or taking a future look a little bit on more technologies than just the nuclear and coal that you were talking about. Having a forward look on more technologies.

In terms of the UCS comments. We had some specific questions and comments both related to the wind costs and the solar costs. So I think what I'll do is I'll just touch briefly on the wind costs and then maybe jot down some furious notes as you guys address them and then I'll move into the solar.

For the wind costs the comment was that the merchant wind costs seem pretty high compared to the IOU-owned facilities. And the reason why it seems like there's a little discrepancy is that none of the contracts signed by the IOU so far have exceeded the market price referent, which has been set at $84 bucks per megawatt hour since the start of the RPS program.

Somewhat related to that is the assumed cost of equity for wind power is high, perhaps by several hundred basis points. If you look at some DOE reports the cost of tax equity for quality wind projects has declined by about three percent over the past four years.

Another question that I guess I don't know a lot about and it seems like maybe it's caught up in the tax code, but the tax benefits -- I'm curious why the tax benefits for the merchant wind facilities are $6 per megawatt hour less than for utility-billed projects.

And then I guess the final part of the

wind question is the assumed life span for wind facilities is 20 years. I'm curious where that came from. To us that seems a little bit low in comparison to if you're comparing across projects with fossil generation and that sort of things.

So that's the wind group of questions. do you want me to go on to solar or wait?

MR. BIGGS: Well this is enough questions. It might be easier for us to tackle them first.

MR. WANLESS: Sure.

MR. BIGGS: And I just might, I'll take a first crack at some of these. And I'm sure Anitha and Joel, especially -- I think typically Navigant is probably best positioned to talk about sort of the inputs on installed costs. Then I would say we sort of worked together to get some of the cost of equity assumptions. And then I think some of the LCOE modeling they're probably better positioned to answer.

So with that I don't know. I might just ask you to take a first crack at some of these, especially -- I guess in asking about sort of the merchant costs on the LCOE basis being higher for an IOU. The second question is sort of why values of incentives would be higher for one owner versus the other. And then the sort of book life.

Let me just ask -- You take a first crack and then I'll add to it if appropriate.

MS. REDNAM: Yes. First of all I would like to say that the Kaplan financing, the structure is different, like I pointed out earlier, for different ownerships. Like merchant have 40 percent debt and 60 percent equity whereas the IOU are 50 and 50 and the muni has no equity, it's 100 percent financed. So based on that your discount rate changes.

And by the way, when the discount rate changes your present value changes and that's why your levelized cost is different for different ownerships. That's why merchants tend to be higher than the IOUs and the munis are the least expensive. They don't even pay taxes.

MR. BIGGS: I think I'd add to that. Because we talked about the very points you brought up. It gets to, one, what is the use of the model. I think we sort of had this philosophical discussion of how we wanted to use the model. And I think at the initial stage we wanted to sort of show more of an apples to apples comparison. What is this technology using the same discount rates, debt rates and so forth. And so, you know, given that you see what you see now in terms of the merchant cost of equity and so forth.

Now I think what you're pointing out to is that some investors have seen the risk of these individual projects being a little bit lower and therefore have agreed to finance these at a lower rate of return and that is true. So I guess we as a group were trying to decide exactly how to reflect that and I think that might be something, that might be a limitation of the model or it might me something we just need to adjust with sensitivity. Because there's so many different variations you could want to do because there's so many different types of owners with different types of tax structures. We didn't know exactly from my perspective, you'll add to this I'm sure. how we wanted to come down on that.

MR. McCANN: One of the beauties of the model is that you can actually easily put in another set of assumptions as a scenario. Actually we considered at one point putting in a different finance structure which had a higher debt financing for merchant plants for renewables because we believed that might be a possibility, that they might be as much as 80 percent debt financed. If you put in 80 percent debt financed you end up with numbers that are much lower, closer to what you see in these contract terms that have been advertised.

So part of this is that we're going off one capital structure that we got from the Board of Equalization. There are alternative ones. They need to be documented in order for us to be able to put them in the model. They can't be just guesses of what they are.

One issue is though that the DOE stuff, materials tend to be nationwide. And California is, as we found in the advanced combined cycle information, California is unique. And there is, in fact one of the questions was about extrapolating from Wisconsin to California. Well it's a 25 percent construction adder to move from the Midwest to California. So there are these various issues that need to be addressed uniquely to California.

You also are going to have different debt structure for a project that is in Washington state, which might be financed by the set of rural co-ops that are there, versus a project that is financed here inside the state of California. So you're going to have these variations. A lot of the contracts that you see for wind power coming around the West are in fact out of the Northwest, not out of California.

MR. BIGGS: I'll touch on the 20 year life because that is something, you know, doing this for awhile, people use different numbers. So the way we came down with 20 years is in talking to some of the leading players in industry as well as many of those are on the board of AWEA, who we just really asked -- we asked them, what is the most appropriate number to use and they guided us toward the 20 year number.

MR. WANLESS: Thank you, that's helpful. On the solar end of things, this is kind of a similar question and so hopefully it won't be too repetitive. But in terms of looking at the levelized cost for solar it seems like they're a little high across the board.

When you look at the concentrating solar projects, the dish and the bethel, the trough there, neither of those required any supplemental energy payments. Which suggests that right now their costs are below, you know, $150 per megawatt hour. So that's kind of a broad question similar to the first wind question.

In terms of more specifics with the solar assumptions. We believe that the analysis shouldn't assume that the investment tax credit will drop to ten percent after 2008. That seems like that's probably an overly conservative assumption and it's not really along -- fits in line with what many policy experts are predicting will happen.

Also just a more general question. And maybe this is again related to the financing structure. But it seems a little odd that the merchant PV costs are more than $200 per megawatt higher than the higher U costs for PV.

And then again coming back to the taking a forward look on more technologies in addition to the IGCC and kind of future costs of nuclear. When you're looking at concentrating solar and concentrating PV, those costs are highly dependant on learning curves and are likely to drop as we're going forward.

I think it would be helpful to the

extent possible that we have numbers that are where we are now and kind of where things may be similar to, you know, the MIT study with their nuclear, the nuclear 2020, nuclear now sort of stuff. Thank you.

MR. BIGGS: Good points. I think maybe Anitha would I think repeat the same logical comments she made on the cost of a merchant IOU. It's a function of the, of the cost of equity assumptions you make and I think that goes to another point I was making. In the market today people are obviously accepting a lower rate of return on their investment.

I'll let Lisa Frantzis who knows this much better than me if she wants to chime in with any questions. Lisa, any points?

MS. FRANTZIS: I think the only thing I would add on the ITC issue is that other analyses that we've always (line cut out) with the Energy Commission we exempt sensitivities looking at investment tax credit. And if the benefits extended beyond 2008 what are the implications for that. In the particular runs that we did we asked the Commission what would they like us to do and they said, you know, we should sort of stick with what the legislation is today and that's basically what we did.

But we have looked at this issue before and we always comment, usually in the body of the text, that there is a lot of potential that the ITC would be extended beyond 2008 to be 30 percent instead of the 10 percent ITC.

And in terms of learning curve impacts I think in the body of the report too we discussed a lot of the concentrating technologies as well as the trough technologies. We certainly do discuss the fact that costs could significantly come down if production costs were to increase. And really, you know, with things like this clearly that's an issue that's hindering current cost reduction potential with those technologies, more than technological breakthrough.

MR. WANLESS: In the sensitivity analysis that you have done with the ITC do you have a sense of how big of an impact that has on the cost looking forward after 2008?

MS. FRANTZIS: I mean, the impact is, you know, it is a fairly significant impact. We just recently completed a study with if you're looking at the resource potential county by county for photovoltaic for residential and commercial buildings for new construction and retrofit. With that study there was a lot of detailed analysis of photovoltaic specifically. We'll provide, you know, all the detailed information in that. Off the top of my head I can't give you exact numbers but I could easily go back to something in the report. Jay, I don't know if you have the numbers off the top of your head?

MR. PAIDIPATI: Not now. That could be provided. They'll be provided when the report is released.

MR. BIGGS: Another thing I might just add. There's three owner structures that are the basis for this cost of electricity modeling. And I think one of the things happening, especially with solar as well as a bit with wind, it kind of gets to what I think your questions are kind of getting at. There's some developments in terms of what a business model, how businesses are approaching this and what type of risk they really do see.

And I mentioned that since you're seeing market prices lower someone is accepting a lower rate of return. That doesn't necessarily mean that's a big thing or it's a worse investment than something else. Someone might -- You're seeing it as a different risk profile so with lower risk you take a lower return. And because of that you're seeing different business partnerships that don't necessarily reflect and they are not the same as a merchant.

So it's not like a merchant really is financing some of these projects. That was something, I think you know, we've talked about, you know, here in this process. And we want to make sure I guess going forward that those types of market developments are going to be reflected. So I guess that's sort of more an added piece of color to sort of help you understand what's going on.

ASSOCIATE MEMBER GEESMAN: I want to come back to the Sterling solar question.

MR. McCANN: Can I just follow up with one thing really quickly?

ASSOCIATE MEMBER GEESMAN: Go ahead, Rich.

MR. McCANN: On that question of pricing the contracts that you see. Something very common in both the aerospace industry and the computer industry is that there's essentially loss leader pricing that occurs in the initial installation of a new technology. That the first sets of technologies are actually sold at a loss in order to increase market share and in order to accelerate the learning curve process, which both of those industries are quite familiar with.

And to a large extent this may also be occurring in this industry. So what you're seeing is in fact the true costs of the installation today in this technology. And in fact that may be different than the contract price that is being report. Now that doesn't mean that the prices -- their expectation is that the price over time is going to fall below what they're signing the contract for and that's what they're, that's what they're aiming for. But in terms of our snapshot, and this is a snapshot model, the cost may be higher than the actual contract prices.

Also on the solar we do have the ability to put in, for someone to externally give us an estimate of how solar costs are going to change based on that learning curve. And then because we have the CSI adjustment, if we can put in a forecast the amount of solar that's in the state in a particular year you can adjust the estimates and be able to forecast what it is, for example, in 2012 after you have 200 megawatts of solar installed. Something along those lines. Those kinds of adjustments can be made in the model pretty easily.

ASSOCIATE MEMBER GEESMAN: Well that may provide a bit of an off-ramp to my question. This Commission has refrained from getting into the debate that rages over whether the Sterling solar projects will be able to come in as contracted for, below the market price referent. Because quite frankly, we hear from disgruntled bidders all the time about how winners cannot produce on the terms that they have contracted for. And our institutional tendency has been to simply discount those comments and not get drawn into it.

I read from your report though some healthy degree of skepticism in terms of the likelihood of either of the two projects in Southern California coming in below the market price referent.

And I assure you that the only thing I know about the price for the Sterling projects is that it is below the market price referent. Rich suggests a hypothesis perhaps that might apply to those plants. That they are in fact loss leaders from a marketing perspective. But do you have any more insight to cast on this?

MR. BIGGS: Lisa, I'd let you take that.

MS. FRANTZIS: There's been a lot of talk about these plants, as you can imagine. When we even did the Arizona solar electric road map, you know, we did have staff from SES at the meetings talking with us regularly. We also talked at length with staff at NREL and, you know, Arizona Public Service, you know, who had facilities to do testing of a lot of these concentrating solar technologies.

You know, without question there are people out there who are skeptical or have some issues or concerns with the claims being made about some of the costs that can be achieved with this technology. On the other hand, you know, when we did talk with folks at SES they're basic claim is that if they can get the production volume of like 250 megawatts versus the 15 megawatts or lower you can get tremendous economies of scale which would drive the costs down. And that's why in our report actually in the out years, you know, we do have sort of a wider range of costs that are provided.

So I think even if you talk with people out in the industry I think the range of numbers that are being quoted are quite large and a lot of it is around the production volumes and the ability to get from where we are today to where the claims need to be in order to drive down the price below the market price referent.

So, you know, having said that, there is no clear, strong due diligence that I am aware of that staff has done that's in a public domain that people can draw upon. You know, a lot of the information we would normally like to see to make a definitive statement about costs, obviously we could not get at that without an NDA. And of course there's all kinds of sensitivities with the manufacturers about sharing that information.

So we basically through discussions with NREL and Arizona Public Service and the Sterling Energy Systems to draw our conclusions about the range. Which we feel fairly comfortable that this range that was provided, you know, in the out years and not for 2006 or '07, are pretty realistic in terms of the range that we think the technology will achieve, given certain production volumes.

ASSOCIATE MEMBER GEESMAN: Thanks, Lisa.

MS. FRANTZIS: Is there anything else?

ASSOCIATE MEMBER GEESMAN: I think that's a good explanation.

If no one else has a question I'd like to jump back to the nuclear issue. And I read your report as concluding that the $2400 a kilowatt estimate that you've assumed is more in line with the $2300 a kilowatt order by the Finnish utility from AREVA in 2003. Now the press has reported there have been pretty significant cost overruns in that Finnish project and I wonder how that impacts the confidence in your conclusion.

MR. BIGGS: We definitely discussed that. And I guess that was -- Within that same discussion of how to balance that there were just as many counter arguments about why -- If a nuclear plant were to be built, you know, there would need to be some certainty, at least by the time it got to California, that some of these kinks would be out of the system I guess. That someone before stepping up to the plate to build one in California some of those problems might need to be taken out.

At the same pint you could argue that some of these are just intrinsic, by the nature they're going to be delayed, so you're always going to come up above. But to make -- I guess where we came out is to make that argument I guess you'd need to come back and say to all these other published studies, the MIT study, that they would somehow have to be sort of systematically discounting those. And we didn't want to go down that path and say, well we're going to discount some of the published studies and go with, I guess industry opinion on what this is likely to cost.

There is a big difference and your point is sort of right on but we tend to draw more toward the industry-published studies.

ASSOCIATE MEMBER GEESMAN: Well I spoke with the Finns in I think it was 2004. They were pretty confident of the $2300 number. So I am not --

MR. BIGGS: Yeah.

ASSOCIATE MEMBER GEESMAN: I am not certain, I am not certain I fully understand why you would discount that specific experience, which to my knowledge is the first in recent times that any western country has actually made an investment in a new plant. Is there a reason why you don't think the Finnish experience is particularly indicative of what a US plant might go through?

MR. BIGGS: No, not specifically, no. It is a good point.

PRESIDING MEMBER PFANNENSTIEL: I would like to go back just a little bit to the whole general sense of how the cost of some of the renewables are changing. And your points about the wind and the difficulty in the steel prices and the solar with the need for silicon production help explain to some extent why the current numbers are higher than the prior numbers. They don't really tell us very much about what is going on going forward.

But another possible explanation for why the current numbers are different from the past numbers could be the current ones are just, are better. They're based on a deeper analysis of available information. And that is perhaps true sort of up and down your list of alternative technologies, it's just that we have more recent information.

So we don't quite know what direction these numbers might be going in the future. I think we're all kind of speculating on whether these are loss leader numbers and therefore going up, whether they're the beginning of a new production cycle and therefore apt to be going down. Something like that.

MR. BIGGS: Sure.

PRESIDING MEMBER PFANNENSTIEL: And maybe in your full report there's a qualitative way for us to assess it. But we are asked often about alternative technologies and, you know, where are the costs going. Are they -- Do you think they are going to go down and over what period of time. And it's a little hard to tell from what is on the written page and the discussions going on here which way they might be going.

MR. BIGGS: Sure.

PRESIDING MEMBER PFANNENSTIEL: I'm wondering, I'm looking for some guidance.

MR. BIGGS: Sure.

PRESIDING MEMBER PFANNENSTIEL: On technology by technology and hope that it is around somewhere.

MR. BIGGS: Sure. Yeah, and I tried -- Lisa, I don't know if you were on at the beginning.

MS. FRANTZIS: Yeah.

MR. BIGGS: I tried to sort of frame the discussion at the very beginning in talking about there is different levels of certainty regarding to how commercially available or how mature these technologies are. So within that discussion I think there's definitely much more certainty around the wind numbers. I think we're very confident that yes, in 2003 people were installing things for $1200 a kilowatt and today it's more like $1900 or $2,000. I don't think there's much disagreement there, especially on wind.

Even I think solar falls into that same category. You can get people familiar with the industry and you're not going to see too much discussion at the end of the day once people agree on dollars per watt AC versus DC and maybe some other sort of definitional things. Prices are what they were. Now where they're going in the future, not that, of course, obviously is a different topic.

But I think there are definitely more mature technologies. I tried to do, at least verbally here, to maybe be a little more helpful with you. To do kind of maybe do a more formalization of that discussion. But yes, some of the other technologies are a bit more -- and we did talk about this in the report. They are more reliant on engineering cost estimates, pilot costs. Lisa, any other comments to add to that?

MS. FRANTZIS: Yeah, I think in terms of addressing your question about future cost reductions. I think we believe for both wind and solar there will be continued cost reduction for those technologies. I think you're seeing sort of the worst in terms of the shortage of supply of turbines and the shortage of supply for the poly-silicon that's feeding the photovoltaic market.

In fact, we have been doing a lot of analysis recently looking at the additional manufacturing capacity coming on line. Silicon plants, which take anywhere from a year and a half to two years, maybe three years sometimes for these new facilities to come on board. So it is not a scarcity of the raw material itself, it's really the manufacturing facilities.

There has been a lot of additional capacity coming on line so we don't think moving forward beyond 2008 that the shortage will be still in place. And therefore we do think that prices will continue to come down from the trend that they were before with really anywhere between a four to seven percent per year cost reduction.

And we're seeing more efficiencies as well in terms of inverter cost reductions, more efficiencies in terms of standardized products and installation techniques to help drive some of the prices down on the system side as well as the module side.

So for solar in the future we do see prices coming down. We even see other advanced technologies coming on board to help continue driving the process on the solar side. So for solar we'll probably see more significant cost reductions in the near future versus wind but we also used the wind prices coming down as well. But I think it will take a bit of time before it gets back to the (inaudible) dollars per kW it was, you know, maybe four years ago or so.

MR. BIGGS: And a lot of that confidence is, you know, because I've been running a lot of these spreadsheet models for clients. We've really tried to dig down, trying to see the long-term trend, the learning curve trend in technological improvement, and then building upon that what we see are cost increases due to steel prices and silicon prices as well as market prices by shortage and pricing decisions.

And then using that when we develop our forecasts we can have a much tighter range in terms of what something, wind or PV or other technologies, could be out five years to ten years. You know, it gives us a much tighter range. And since prices are high you are seeing much more investment in silicon manufacturing facility, turbine blade manufacturing facility.

Now I think one thing we've seen over the last few years from our commercial clients is that a year ago maybe or even two years ago commercial clients would make the argument, well we don't see the firm commitment from policy makers that the 30 percent investment tax credit is here to stay or the 1.9 percent production tax credit for wind is going to stay. Therefore I don't want to invest in a big manufacturing operation, put steel in the ground, put forth a lot of capital and then just have the policy makers pull the plug on an incentive and the market dries up.

I think now what these same decision makers are seeing is that it's not even just the incentives but those are shoring up whether there's going to be a carbon tax or other renewable incentives. I think there's much more confidence that policy makers are committed to action, I guess, as well as the belief that with scarcity of fuel and other factors that the market, whether it's going to be in the US or outside the US, is going to be robust enough to sort of make that investment pay off. The manufacturing capacity for this is more likely to come on line today than it was just even a few years ago. We have another question.

PRESIDING MEMBER PFANNENSTIEL: Jane.

MS. TURNBULL: Jane Turnbull again. I'd like you to comment on two adjectives that I hear sort of bantered around fairly often. One is the word mature and the other is the word aging.

MR. BIGGS: Sure.

MS. TURNBULL: Depending upon the impact that the individual wants to make they choose one of these two words. How would you define the two words?

MR. BIGGS: Yes, that's a good point because now that you've raised the question I think maybe we could think back and make sure we be a little bit more precise. Especially in this analysis there's sort of two areas where it comes into play.

One, a maturity will depend on how confident you can be in terms of what the costs today are going to be. It also comes into play in terms of how much additional cost reduction could there be in the future. I think we probably need to make that distinction. I think primarily in this conversation where we're talking about costs today we've been talking about from the maturity standpoint of how confident we are in that the cost would be that for an installation today.

MS. TURNBULL: Would you define aging.

MR. BIGGS: I guess I don't use that much so I don't know as much or what context it's been used.

MS. TURNBULL: People are talking, you know, in conversation about aging power plants.

MR. BIGGS: Aging power plants. Well

that, specific power plants may be towards, you know, costs and the performance today versus something new in the ground. I guess I'm just not familiar with sort of the discussions that gone on using aging.

I would thin, you know, in terms of in alternative technologies, things that we've talked about here, that aging isn't sort of applicable to any one of these. But I guess if someone were to use it that might say that they're further down in the learning curve and that you won't see as much cost reduction. But maybe Will here --

MR. WALTERS: In terms of, you know, power plants that are in today, when we're talking about aging it's technologies that just would not be built today. There are also just older plants that are just getting past their useful life or what their book life would have been. In many cases way past what their book life would have been. Some of the boiler plants are, I don't know, 50-plus years old now and still running.

So I think when you hear people talking about aging facilities that's what they're talking about. They're talking about the old power boilers primarily and the fact that these need to be changed over. Either, you know, repowered or just shut down.

MS. TURNBULL: I guess I shouldn't have played cute. In fact, the context in which aging is generally being used or what I'm hearing now is in the context of the nuclear power plants, our existing ones. And I would like the comment to the effect of, are they really aging or would you consider them aging?

MR. BIGGS: I guess I don't have any strong opinions on that, is that the right word, to answer that. Anyone else?

MR. KATOFSKY: This is Ryan. They're certainly not getting any younger in the sense of the last comment about how once the plant is built, you know, it's typically aging. It's not so much about the technology development but that particular asset. Any asset that's in the ground, you know, that's going to be the case. I was going to say that mature and aging, you know, describes me pretty well also. (Laughter)

MS. TURNBULL: Thanks.

MR. BIGGS: Good, thank you.

MR. NELSON: Mark Nelson from Edison again. I had a comment. I was at GE's, I guess let's call it a press conference a couple of weeks ago when Jeff Immelt announced that GE had a $50 billion, with a B, backlog in wind turbines and other, you know, green devices.

Now how much of that is strictly wind versus how much of that is other activity we don't know. They didn't break it down. But, you know, they will nibble through that. So, I mean, I do think that, you know, we will have some transitory pricing in that sense. Not that GE is, you know, the leading producer of wind either. They're just one of the turbine manufacturers.

I had a philosophical issues and I don't know. It may be out of scope with what we're doing right now but -- With some of these resources, for instance geothermal, they tend to be coincident with system peak. They themselves when you put them into a model like a Henwood or a Global Insight model now I guess, you'll have certain impacts.

Whereas a wind resource which tends not to be coincident with peak, it tends to be largely an energy resource, may still when you put it into the model again, may still show cost changes but may also require you to put in capacity resources, especially with our increasingly peaky system.

And I guess I'm just wondering, is that something that we should be looking at as we look at these sorts of resources or is that really relegated further down in the IEPR process to least-cost/best-fit, if you will?

ASSOCIATE MEMBER GEESMAN: Well we continue our quest to figure out what least-cost/best-fit actually means and I think we will spend some additional time this summer trying to dig into that. As you know, the renewable portfolio standard, and arguably AB 32, is energy oriented rather than capacity oriented.

I think the Commission fully recognizes that we've got system needs that require both capacity as well as energy and it is something that we need to properly assemble the various component pieces before being able to make a recommendation as to what your portfolio should look like.

MR. NELSON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Further questions or discussion?

Anything else to come up? Any last comments from our presenters and the panel?

MR. ALVARADO: This is Al Alvarado with Energy Commission staff. I just sort of wanted to sort of -- we had a pretty broad discussion about so many different subjects on this project and I sort of wanted to bring part of this together.

The original purpose of this project initially, bringing it into pieces, is one, to develop a tool. Commissioner Geesman, you've asked us numerous times in the past to be nimble in our analytical efforts.

I do think that this tool that we have today at least will allow us to conduct the various types of analysis to figure out the different sensitivities about how one factor may affect ultimately the cost of one generation technology and the next or to try to address questions about different natural gas price forecasts. I do think this tool allows us to conduct those type of analyses really quickly.

The second phase of the project is to at least identify a number of different generation technologies given time, staffing and budget constraints. We did target just a handful of different generation technologies. It is not all inclusive of every technology possible. I think that would be one of the next steps forward.

The goal here was to come up with the best information or the most current information available to try to characterize a lot of these facilities so that when you use a tool like this you have common financial information that is used from one technology to the next so at least they will be comparable when we develop these screening curves. So I do think that's one goal that I think we have been able to accomplish.

There's questions about why we selected only one coal technology. The request was to look at clean coal and given our constraints we selected just one technology. I know that there's been other efforts within the PIER group to look at clean coal technologies too.

We are requesting comments, any written comments by June 22. Our goal here is to seek any effort to try to validate some of the information, the characterization of each resource here so that at least we have something to bring forward to the IEPR Committee as a building block for continuing our resource planning efforts.

ASSOCIATE MEMBER GEESMAN: Thanks for bringing that up, Al, because I do want to emphasize, from the Electricity Committee in particular, we did try and put the primary challenge on you in developing an analytic tool and a methodology that would be transparent and hopefully would receive broad use outside the Commission as well as inside.

And at least in terms of my initial review of it I think you've succeeded marvelously in that regard. I am hopeful that the review comments you get, if not the formal public comments between now and the 22nd, some of the peer-to-peer reactions can focus on that methodology as well as the specific values that you've come up with in this year's IEPR as to what specific technology costs are likely to be.

Ultimately over the long haul I think the development of the methodology and its usefulness is probably likely to have a lot more value than whatever assumptions we make for specific technologies in this cycle.

MR. ALVARADO: Thank you, Commissioner. I do think that a lot of credit is given to some of our staff who really put out a heroic effort to pull a lot of this information together.

PRESIDING MEMBER PFANNENSTIEL: I want

to add my thanks. I think that the work is really incredibly useful and will be so going forward. So thank you for the underlying work and the really good discussion today. I think that we got a lot out of it for the IEPR.

Is that it? Nothing further?

We'll be adjourned.

(Whereupon, at 12:24 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 5th day of July, 2007.